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**VIA ELECTRONIC MAIL ONLY:** DOER.APS@mass.gov

August 20, 2021

Darchelle Petion
Commonwealth of Massachusetts
Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

**Re: Comments on 2021 Alternative Energy Portfolio Standard Straw Proposal**

Dear Ms. Petion:

On behalf of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or "Company"), I am pleased to comment on the Department of Energy Resources' ("DOER") straw proposal issued July 20, 2021 ("Straw Proposal") regarding the Alternative Energy Portfolio Standard ("APS"), 225 CMR 16.00.

Per 225 CMR 16.07(3), the DOER completed a review of the APS after a public comment period. The review was to "include, but not be limited to, an examination of the costs and benefits of the program to ratepayers, an examination of the effectiveness of the program in meeting the energy and environmental goals of the Commonwealth, and an evaluation of whether the Minimum Standard or its rate of increase, as established in 225 CMR 16.07(2), should be adjusted." The DOER issued the Straw Proposal in response to this review.

National Grid is pleased to offer the following comments on the Straw Proposal, as well as additional comments on items not addressed in the Straw Proposal.

## I. General Comments

National Grid supports and shares the Commonwealth's ambition to reduce its climate emissions to "net zero" by 2050. National Grid supports the continuation of the APS as it has been a useful tool to reduce greenhouse gas ("GHG") emissions associated with thermal sources and end uses. As stakeholders have noted, reducing GHGs in the heating sector is a particularly important and challenging element of economy-wide decarbonization, requiring a broad range of new strategies and expanded fuel sources. National Grid has previously advocated the points included in this section, below, to the DOER, but offers them again, here.

A. Increase Funding for Heat Pumps

The APS should increase the level of incentive funding for heat pumps. Together with the incentives offered by the Program Administrators under the utilities' Three-Year Energy Efficiency Plans, this additional funding can help heat pumps become a more cost-effective option for mass-market customers. In addition, the APS requirements for heat pumps should be amended to allow for incentivizing partial electrification of a customers' heating (i.e., requiring less than 90% displacement of existing heating load). This change would achieve GHG reductions where they are feasible, rather than limiting incentives to those customers whose preferences or resources allow them to choose a fully electrified heating system. Finally, Air Source Heat Pumps should not be disqualified from the APS for receiving subsidies through the MassSave program.

B. Maintain the Focus on Electric Technologies

The region's long-term heating needs will be best served by a hybrid energy system that continues to use a significant proportion of low-carbon or zero-carbon fuels, along with efficient electric heating, to offer the most reliable, resilient, and affordable heating energy to customers. There should be policies to help advance low and zero-carbon fuels, including renewable natural gas ("RNG") and low or zero-carbon hydrogen. However, the APS should continue to focus on electric-related technologies, in addition to solar thermal. Combining these efforts with gas decarbonization technologies under the APS would introduce a level of complexity into the program that would make it more difficult to administer, comply with, and evaluate. Creating an APS requirement for sellers of natural gas would also result in an inappropriate cross-subsidy from gas customers to electric thermal users and would not address lack of participation by the delivered fuel sector. In addition, including sellers of natural gas in the APS would be unlikely to provide the level of policy certainty necessary to bring RNG or low-carbon hydrogen developers into the market, compared to a policy with specified targets for qualifying fuels over time.

As such, a separate policy mechanism, such as a procurement standard for RNG or low-carbon hydrogen, would more effectively catalyze the market for decarbonized heating fuels than would including these fuels in the APS program. It is important to advance the most affordable and equitable strategies for heat decarbonization for the Northeast, given the unique climate, building stock and energy system characteristics of the region.

C. Continue to Encourage Combined Heat and Power Systems

Certain studies have claimed that Combined Heat and Power ("CHP") projects should be disqualified from the APS because they have brief payback periods, and inadequate emissions reductions.[1]

The APS has created numerous benefits for customers, including economic and environmental benefits associated with CHP technologies. CHP systems are increasingly cost-effective and

[1] See, e.g., The Daymark Energy Advisors "Alternative Energy Portfolio Standard Review," (October 30, 2020) at 18 and Figure 28.

create reductions in GHG emissions, and should continue to qualify for Alternative Energy Certificates ("AECs") under the APS. National Grid delivers energy-efficient products and services to our customers through our energy efficiency ("EE") programs where we aim to reduce energy consumption in the Commonwealth. National Grid supports the installation of CHP projects with EE program incentives; a reduction in the availability of incentives through the APS would likely increase the level of EE incentives sought by customers to install CHP facilities, or decrease customer interest in such installations. The Company works with customers through our EE programs who rely on the AECs and program incentives to offset operations and maintenance costs and total project costs. Of all the systems installed in over the last four years, the average payback without the AECs was over six years. Several of these systems would not have been installed if the AECs were not available.

CHP continues to be an important solution to customers' energy needs and will continue to decrease GHG emissions over the life of every installation. Based on these factors, National Grid believes that CHP should continue to qualify for AECs.

D. Consider Other Massachusetts Decarbonization Policies

Generally, National Grid supports the most cost-effective and efficient policies for reducing GHG emissions. National Grid also supports the costs of decarbonization policies being shared equitably among energy users (i.e., electric customers, gas customers, delivered fuel customers, and others). In that context, National Grid recommends that modifications to the APS be considered in light of the Commonwealth's multiple policies and standards to support decarbonization, which have so far largely been focused on electricity, and paid for by electric customers. Since the APS went into effect in 2009, the Legislature has enacted many additional policies to support renewable energy and reduce emissions. Any proposed changes to the APS should not be viewed in isolation; rather, it is appropriate to consider other clean energy regulations and policies that have (and will) increase costs for electric distribution companies' ("EDCs") customers, and determine whether changes to the APS are cost-effective in comparison.

New legislative and regulatory policies since 2009 include:

- Long-term power purchase agreements for clean energy and offshore wind energy, pursuant to St. 2009, c. 269, sections 83A, C, and D (as amended), with targets to procure the equivalent of 1,200 megawatts ("MW") of clean energy and up to 5,600 MW of offshore wind;
- 2,000 MW of solar through the Solar Carve-out and Solar Carve-out II Compliance Obligations, which are part of the RPS Class I Minimum Standard at 225 C.M.R. 14.07;
- Net metering expansions, pursuant to G.L. c. 164, s. 138, 139, 139A (as amended);
- Clean Energy Standard and Clean Energy Standard for Clean Existing Generation Units, promulgated through 310 C.M.R. 7.75;
- 3,200 MW of solar through the Solar Massachusetts Renewable Energy Target, promulgated pursuant to St. 2016, c.75, s. 11;

- Amendment to the Class II Renewable Portfolio Standards which increases the Alternative Compliance Payment ("ACP") rate and minimum standard obligation percentage which would increase EDC customers' costs;
- Increase in the Class I RPS, per St. 2021, c. 8, s. 32; and
- Clean Peak Energy Portfolio Standard, promulgated through 225 C.M.R. 21.00.

Given these many initiatives and their related costs, the Company recommends DOER focus on sharpening the effectiveness of the APS, as discussed in Sections I. A, B, and C of these comments, above, rather than dramatically expanding the program's scale and cost. In particular, dramatically increasing the annual requirements, or boosting the ACP level, could lead to a return of a shortage in AECs, increases in ACP payments from load serving entities and increases in cost without commensurate program impact. Instead, the Company favors more modest changes in overall future costs of the APS along with refinement and refocusing of the benefits to the most promising resources the program supports.

E. The APS Should Prioritize the Most Cost-effective GHG Emissions Reductions

The APS should prioritize the most cost-effective GHG emissions reductions and continue to focus on technologies which are electricity-related, as well as solar thermal. The APS also should continue to be funded by electric customers to ensure the broadest base of inclusion in supporting the goals of the APS.

It would be reasonable to adjust the factor levels within the APS to better align with customer payback thresholds and project economics. Also, the Daymark Study conclusions related to CHP units should be re-examined against the Company's data on specific CHP installations before becoming generally accepted.

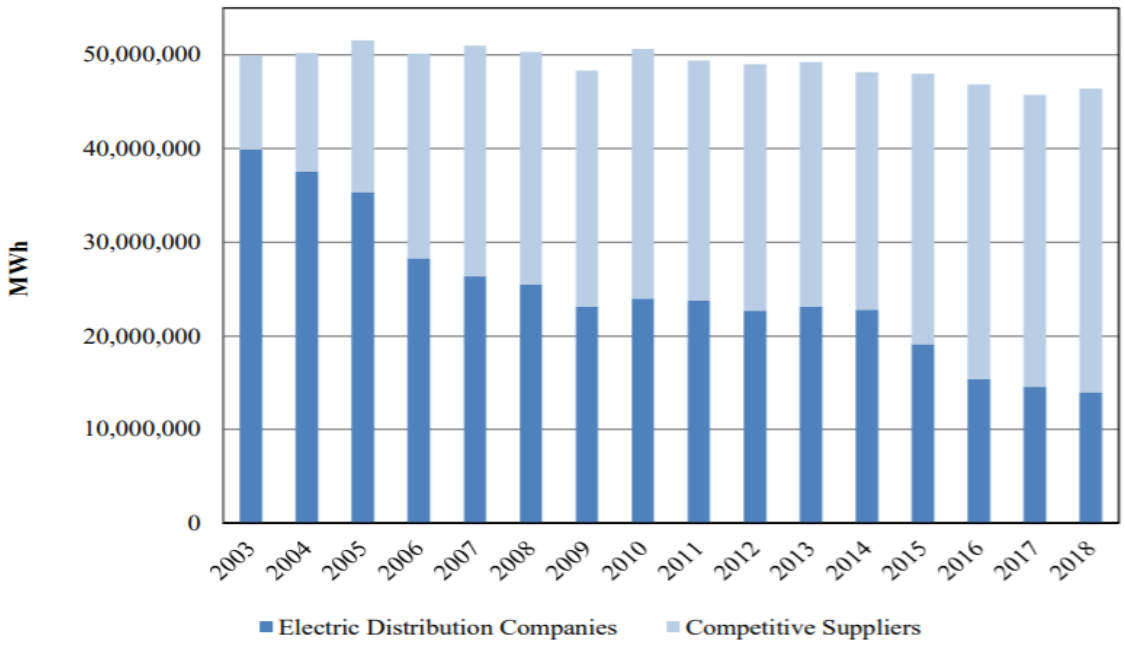
As part of the broader set of policies that the Commonwealth has embraced to reduce carbon emissions and increasingly electrify heating needs, it is also reasonable to provide more support to technologies that provide the greatest GHG reduction potential. However, this should only be one factor, along with others like resource potential, customer interest and acceptance, and project economics, in determining the level of APS support to a specific technology.

F. If APS Percentages Must Increase, Then No Supply Contracts Should Be Exempt

If the DOER must increase the APS obligation percentage, then no existing electricity supply contracts should be exempt. Many EDC customers purchase their commodity service from competitive suppliers through long-term contracts, and a significant portion of National Grid's distribution customers purchase power through the Company's Municipal Aggregators' tariff. Contracts for municipal aggregations may even include a section to address regulatory events, in which case the competitive suppliers can pass along an increase in costs to participating customers. Competitive suppliers for non-municipal aggregation customers may also have this contract language. If the DOER were to exempt any of this electricity load from an increase to the APS obligation, an EDC's Basic Service customers would bear a disproportionate share of the increase because Basic Service generally employs shorter contracts and may not qualify for such an exemption. In addition, if the DOER were to apply an APS increase mostly to Basic Service

customers, it is not guaranteed to significantly further the state's Global Warming Solutions Act goals because Basic Service load, as a percentage of EDC load, has decreased significantly over the years, as illustrated in the graph below, which was included in the DOER's 2018 Annual Compliance Report.[2]

**Figure 1 Retail Load Obligation by Supplier Type, 2003-2018**




Accordingly, if the DOER does decide to move forward with an APS increase, it should not exempt any load from such increase, or it risks imposing a disproportionate share of the cost burden on Basic Service customers, and it may not even achieve the additional reductions that are sought by the increase.

## II. The Straw Proposal is More Expensive Than Necessary to Achieve the Targeted GHG Reductions

The DOER's proposal to increase demand for AECs, decrease the supply of AECs, and increase the ceiling price cap are all factors that will increase costs for EDC customers, as discussed below.

### A. Proposed Increased Demand for AECs

Retail electricity sellers, or load-serving entities ("LSEs"), annually must procure a minimum percentage ("Minimum Standard") of AECs that corresponds to a percentage of electricity sales.

[2] DOER, "2018 Annual Compliance Report: Renewable Energy Portfolio Standard (RPS), Alternative Energy Portfolio Standard (APS), Clean Energy Standard (CES)," (June 9, 2021). Available at: https://www.mass.gov/doc/rps-aps-2018-annual-compliance-report-final-6-9-21/download.

The DOER proposes a one-time increase of 2% in 2023, and then a further annual increase in the Minimum Standard of 0.25%. The proposed increases are an attempt, in conjunction with a decrease in eligible supply of AECs, to address supply-demand imbalances in the market. National Grid does not support these proposed increases because demand is expected to increase significantly in the next decade, due to further electrification, as discussed below.

The Company used forecast data published by ISO-New England, Inc. ("ISO-NE") in ISO-NE's 2021 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT") Report in order to project the Compliance Load Obligation for Massachusetts for the next ten years,[3] excluding electric load from municipal light plant ("MLP")[4] customers. The 2021 CELT Report assumes, among other things, "energy and demand impacts of heating and transportation electrification by state."[5]

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[3] The CELT Report is a generally accepted long-term electricity load forecast for New England, which is published by ISO-NE annually. ISO-NE provides historical, forecast and weather-normalized energy and loads for the CELT Report 2021 - 2030 in Excel spreadsheet format, including model inputs and other data supporting the long-run 2021 forecasts. In order to project the Compliance Load Obligation for Massachusetts for the next ten years, the Company used Tab 2c "Energy" (in gigawatt-hours) of "2021 CELT Forecast Detail: ISONE Control Area, New England States, RSP Sub-areas, and SMD Load Zones," available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Annual%20Load%20Forecast%20Data.

[4] Municipal electric utilities include municipal electric departments, municipal light boards, and municipal light plants.

[5] See 2021 CELT Report Introduction, available at: https://www.iso-ne.com/system-planning/system-plans-studies/celt/.

**Table 1: Projected Massachusetts Compliance Load Obligation: 2021 - 2030**

| | MA NET CELT Forecast (MWH) | % MLP | Compliance Load Obligation (in MWh)[6] |
|---|---|---|---|
| 2021 | 55,619,000 | 14% | 47,832,340 |
| 2022 | 57,158,000 | 14% | 49,155,880 |
| 2023 | 57,545,000 | 14% | 49,488,700 |
| 2024 | 58,010,000 | 14% | 49,888,600 |
| 2025 | 58,177,000 | 14% | 50,032,220 |
| 2026 | 58,552,000 | 14% | 50,354,720 |
| 2027 | 59,245,000 | 14% | 50,950,700 |
| 2028 | 60,308,000 | 14% | 51,864,880 |
| 2029 | 61,167,000 | 14% | 52,603,620 |
| 2030 | 62,299,000 | 14% | 53,577,140 |

Massachusetts' Compliance Load Obligation for 2020 was 43,624,906 megawatt-hours ("MWh"), which is low compared to recent years and compared to projected load through 2030. An annual Minimum Standard increase of 0.25% based on the 2020 load would not show significant demand increases for AECs. However, assuming that electric load increases from further electrification (as the 2021 CELT Report does), the DOER's proposed 0.25% increase would result in significant increases in AEC demand, as illustrated in the following table.

[6] The Massachusetts CELT forecast includes all load including MLPs. To determine the non-MLP electric load, the Company estimated MLP load, and deducted it to derive the Commonwealth's APS Compliance Load Obligation.

**Table 2: Demand for AECs Under Current Percentages: Current 2020 Compliance Load Versus Future Electrification Compliance Load**

| | Current Percentage | 2020 Compliance Load (MWH) Each Year | AECs Needed | Compliance Load Obligation (MWH) | AECs Needed with Electrification | Increase in AECs Needed due to Electrification |
|---|---|---|---|---|---|---|
| 2021 | 5.25% | 43,624,906 | 2,290,308 | 47,832,340 | 2,511,198 | 10% |
| 2022 | 5.50% | 43,624,906 | 2,399,370 | 49,155,880 | 2,703,573 | 13% |
| 2023 | 5.75% | 43,624,906 | 2,508,432 | 49,488,700 | 2,845,600 | 13% |
| 2024 | 6.00% | 43,624,906 | 2,617,494 | 49,888,600 | 2,993,316 | 14% |
| 2025 | 6.25% | 43,624,906 | 2,726,557 | 50,032,220 | 3,127,014 | 15% |
| 2026 | 6.50% | 43,624,906 | 2,835,619 | 50,354,720 | 3,273,057 | 15% |
| 2027 | 6.75% | 43,624,906 | 2,944,681 | 50,950,700 | 3,439,172 | 17% |
| 2028 | 7.00% | 43,624,906 | 3,053,743 | 51,864,880 | 3,630,542 | 19% |
| 2029 | 7.25% | 43,624,906 | 3,162,806 | 52,603,620 | 3,813,762 | 21% |
| 2030 | 7.50% | 43,624,906 | 3,271,868 | 53,577,140 | 4,018,286 | 23% |

For example, the Minimum Standard of 2025 is 6.25% and at current load levels would require 2.7 million AECs for compliance. However, due to increased electrification, the expected number of AECs to comply with the APS is projected to be 15% higher, or 3.1 million AECs, because the 2025 expected Compliance Load Obligation is 15% higher than the 2020 load.

Electrification will automatically significantly increase the demand for AECs, which will therefore increase prices if the supply of AECs does not increase by similar percentages. The one-time increase of 2% in 2023 is unnecessary to correct the market imbalance. Rather, it likely will result in a market with demand far outstripping supply, and AEC prices trading near the ceiling price. For example, in 2030 the 2% increase will result in 23% higher AEC demand, or 937,000 AECs, than demand based on the current Minimum Standards. The table below compares the current and proposed Minimum Standards and the estimated Compliance Load Obligation. In 2030, the electrification AEC requirement would be 4 million AECs. With the additional 2% increase in 2023, the AEC requirement would be almost 5 million AECs.

**Table 3: Demand for AECs With Future Electrification: Current Obligation Percentages Versus Straw Proposal Percentages**

| | Compliance Load Obligation (MWH) | Current Percentage | Current AECs Needed | Proposal Percentage | Proposal AECs Needed |
|---|---|---|---|---|---|
| 2021 | 47,832,340 | 5.25% | 2,511,198 | 5.25% | 2,511,198 |
| 2022 | 49,155,880 | 5.50% | 2,703,573 | 5.50% | 2,703,573 |
| 2023 | 49,488,700 | 5.75% | 2,845,600 | 7.50% | 3,711,653 |
| 2024 | 49,888,600 | 6.00% | 2,993,316 | 7.75% | 3,866,367 |
| 2025 | 50,032,220 | 6.25% | 3,127,014 | 8.00% | 4,002,578 |
| 2026 | 50,354,720 | 6.50% | 3,273,057 | 8.25% | 4,154,264 |
| 2027 | 50,950,700 | 6.75% | 3,439,172 | 8.50% | 4,330,810 |
| 2028 | 51,864,880 | 7.00% | 3,630,542 | 8.75% | 4,538,177 |
| 2029 | 52,603,620 | 7.25% | 3,813,762 | 9.00% | 4,734,326 |
| 2030 | 53,577,140 | 7.50% | 4,018,286 | 9.25% | 4,955,885 |

B. Proposed AEC Supply Decrease

Basic economics dictate that as demand increases, and supply remains the same, prices will increase. And if demand increases while supply simultaneously decreases, prices will increase even higher.

The tables above demonstrate that demand for AECs will significantly increase over the next decade, without the 2% Minimum Standard increase in 2023, due to the expected further electrification of the grid and the existing 0.25% annual increases. The proposed increase to the 2023 Minimum Standard by 2% would only exacerbate these expected AEC demand increases. The Straw Proposal also includes changes to limit the supply of AECs through 2030 by removing some technologies from eligibility (which did not create many AECs) but, more significantly, "phasing down" qualified Generation Units utilizing natural gas (CHP and Fuel Cells).

Table O within the DOER's 2018 Annual Compliance Report[7] shows that, historically, most AECs were created by CHP natural gas.

[7] Available at: https://www.mass.gov/doc/rps-aps-2018-annual-compliance-report-final-6-9-21/download.

**Table O APS Compliance by Generation Type, 2012-2018**

| Fuel Type | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | |
|---|---|---|---|---|---|---|---|---|---|
| Biomass | - | - | 2,689 | 2,797 | 3,138 | 2,548 | 5,495 | 6,525 | 0.3% |
| Digester Gas | - | - | - | 855 | 531 | 893 | 152 | 5,578 | 0.3% |
| Fuel Cell | - | - | - | - | - | - | - | 19,758 | 1.0% |
| Flywheel Storage | 303 | 3,186 | 489 | 377 | 98 | 2,724 | - | - | 0.0% |
| Heat Pump - Air | - | - | - | - | - | - | 2,087 | 28,416 | 1.4% |
| Heat Pump - Groun | - | - | - | - | - | - | - | 71,910 | 3.6% |
| Liquid Biofuels | - | - | - | - | - | - | 406,673 | 294,337 | 14.6% |
| Solar Thermal | - | - | - | - | - | - | 121 | 44,198 | 2.2% |
| CHP - Biomass | - | - | 2,689 | 2,797 | 3,138 | 2,548 | 1,659 | 1,924 | 0.1% |
| CHP - Natural Gas | 324,619 | 347,993 | 529,462 | 826,966 | 890,835 | 938,838 | 1,495,505 | 1,446,495 | 71.7% |
| CHP - Muni Waste | - | - | 145,497 | - | - | - | 105,658 | 96,936 | 4.8% |
| CHP - Waste Energy | - | - | - | 855 | 531 | 893 | 486 | 30 | 0.0% |
| TOTAL | 324,922 | 351,179 | 680,826 | 834,647 | 898,271 | 948,444 | 2,017,836 | 2,016,107 | 100.0% |

In 2018, 72% of the AECs were created by CHP natural gas Generation Units. The Straw Proposal, if implemented, will significantly decrease the number of AECs from CHP natural gas until they eventually do not qualify by 2030. The increase of demand for AECs due to load increases from electrification combined with the expected decrease in supply of AECs (due to the removal of the CHP natural gas AECs), will create an AEC shortage in the market.

The table below uses the 2018 AEC supply from CHP natural gas units as a proxy for future generation through 2030. The table includes the annual "phasedown" factors proposed in the Straw Proposal to illustrate the reduction of AECs available in the market due to the phasedown. The table also illustrates the increasing number of AECs that must be procured in the market from non-CHP natural gas generation units.

**Table 4: Shortfalls of AECs Without Natural Gas CHP: Current Percentages Versus Straw Proposal Percentages**

| | | | | | Current Regulations – Maintain Min Standards | | | Straw Proposal – Increase Min Standards | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 AECs | Factor | Proposed AECs | Compliance Load Obligation (MWH) | Current Percentage | Current AECs Needed | Shortfall without CHP Natural Gas | Proposal Percentage | Proposal AECs Needed | Shortfall without CHP Natural Gas |
| 2021 | 1,446,495 | 1.0 | 1,446,495 | 47,832,340 | 5.25% | 2,511,198 | 1,064,703 | 5.25% | 2,511,198 | 1,064,703 |
| 2022 | 1,446,495 | 1.0 | 1,446,495 | 49,155,880 | 5.50% | 2,703,573 | 1,257,078 | 5.50% | 2,703,573 | 1,257,078 |
| 2023 | 1,446,495 | 0.7 | 1,012,547 | 49,488,700 | 5.75% | 2,845,600 | 1,833,054 | 7.50% | 3,711,653 | 2,699,106 |
| 2024 | 1,446,495 | 0.6 | 867,897 | 49,888,600 | 6.00% | 2,993,316 | 2,125,419 | 7.75% | 3,866,367 | 2,998,470 |
| 2025 | 1,446,495 | 0.5 | 723,248 | 50,032,220 | 6.25% | 3,127,014 | 2,403,766 | 8.00% | 4,002,578 | 3,279,330 |
| 2026 | 1,446,495 | 0.4 | 578,598 | 50,354,720 | 6.50% | 3,273,057 | 2,694,459 | 8.25% | 4,154,264 | 3,575,666 |
| 2027 | 1,446,495 | 0.3 | 433,949 | 50,950,700 | 6.75% | 3,439,172 | 3,005,224 | 8.50% | 4,330,810 | 3,896,861 |
| 2028 | 1,446,495 | 0.2 | 289,299 | 51,864,880 | 7.00% | 3,630,542 | 3,341,243 | 8.75% | 4,538,177 | 4,248,878 |
| 2029 | 1,446,495 | 0.1 | 144,650 | 52,603,620 | 7.25% | 3,813,762 | 3,669,113 | 9.00% | 4,734,326 | 4,589,676 |
| 2030 | 1,446,495 | - | - | 53,577,140 | 7.50% | 4,018,286 | 4,018,286 | 9.25% | 4,955,885 | 4,955,885 |

Without the replacement of these CHP natural gas AECs, the market appears to be very undersupplied throughout the next decade, leading to shortage conditions which will raise compliance costs close to ceiling prices. There is no guarantee that new Generation Units will become qualified to replace the CHP natural gas AECs, nor will the new Generation Units likely meet the increasing AEC demand from the electrification of the grid.

C. Increasing the Alternative Compliance Payment Rates Is Unjustified and Removes Customers' Protections from Unreasonably High Costs

The Alternative Compliance Payment ("ACP") allows a retail supplier to comply with the APS when it cannot purchase AECs to meet the Minimum Standards, but the ACP also provides a cap on EDC customer costs. The ACP rates act as "ceiling prices" to protect electricity customers against unreasonably high market prices for AECs, which are often purchased at a price close to the ACP rate when there is a shortage of AECs to meet demand. For the RPS and the APS, certificate shortages have occurred for all the portfolio standards at some point and the applicable ACPs provided some customer protection. The ACP rate is intended to reduce the EDC customers' exposure to higher program costs as the percentage requirements annually increase, and it also protects EDC customers as the compliance loads increase due to electrification.

In its December 2020 comments, National Grid estimated the compliance costs for LSEs, both in ACP rates and purchases of AECs, as $315 million from 2009 to 2019. It also estimated the compliance price per MWh in the table below.

**Table 5: EDCs' Estimated Total APS Compliance Costs, Compliance Prices, and ACP Rates: 2009 – 2019**

| | Alternative Compliance Payment Rate | Compliance Price ($ / MWh) | Compliance Price % Below ACP Rate | Compliance Costs ($ millions) |
|---|---|---|---|---|
| 2019 | 23.13 | 14.2 | -38.6% | 30.3 |
| 2018 | 22.64 | 18.9 | -16.5% | 39.5 |
| 2017 | 22.23 | 20.8 | -6.4% | 40.3 |
| 2016 | 22.00 | 21.8 | -0.9% | 40.9 |
| 2015 | 22.02 | 21.9 | -0.5% | 39.3 |
| 2014 | 21.72 | 21.6 | -0.6% | 36.2 |
| 2013 | 21.43 | 21.2 | -1.1% | 30.7 |
| 2012 | 21.02 | 20.6 | -2.0% | 24.5 |
| 2011 | 20.40 | 20.0 | -2.0% | 18.2 |
| 2010 | 20.00 | 19.0 | -5.0% | 11.9 |
| 2009 | 20.00 | 17.8 | -11.0% | 2.9 |
| Total | | | | 314.7 |

The market has experienced a shortfall in AEC supply from 2009 through 2017 which resulted in multiple LSEs making an ACP to comply with the APS. From 2010 through 2016 over 50% of LSEs' obligations were met by the ACP. Additionally, the table highlights that the compliance price has been slightly below the ACP rate in shortage years. This type of trading pattern

(compliance price slightly below the ACP rate) will continue in the future in years when there are shortage conditions. Based on the above analysis of demand and supply, shortage conditions will exist over the next decade which will therefore result in prices near the ACP rate.

The Straw Proposal includes an increase of the APS ACP rate to $40 without reasonable justification. In the Straw Proposal and the virtual briefing on July 27, 2021, it was stated the ACP should be raised by 2023 to align with the 2023 RPS Class I ACP rate, but no reason was given other than it would be less complicated if standards had the same ACP rate. Additionally, it does not seem fair that the ACP for an RPS Class I resource, which consists of capital-heavy investments such as offshore wind, would have the same ceiling price as an APS Generation Unit. Also, as the Company described above, a large, short market will be created for the APS if the Straw Proposal is implemented, and there may be future situations that an AEC trades higher than an RPS Class I REC, which would seem illogical.

Per the DOER's own study ("DOER APS Review"), the APS market would need to be stabilized to "with an AEC price of at least $15/AEC" to result in emission reductions.[8] If shortage conditions occur and the ACP rate is not increased to the RPS Class I ACP rate as the Straw Proposal suggests, AEC prices will still trade over $20 per AEC which should result in effective emission reductions if the $15 per AEC price is the necessary threshold. Increasing the ACP rate to $40 would only result in windfall profits to APS Generation Units over the next decade, as shown in the following tables, which anticipates shortage conditions and compares compliance costs if the Straw Proposal is implemented. The table below shows the increase in costs due to the ACP rate increase if the Minimum Standard percentages remain at current levels.

**Table 6: Estimated Compliance Costs, at Current Percentages, from Straw Proposal ACP Rate Increases: 2023 - 2030**

| | Compliance Load Obligation (MWH) | Current Percentage | Current AECs Needed | Current ACP Rate (in $) | Current Costs (in $) | Proposed ACP Rate (in $) | Proposed Costs | Increased Costs |
|---|---|---|---|---|---|---|---|---|
| 2023 | 49,488,700 | 5.75% | 2,845,600 | 24.76 | 70,457,062 | 40.00 | 113,824,010 | 43,366,948 |
| 2024 | 49,888,600 | 6.00% | 2,993,316 | 25.26 | 75,611,162 | 40.00 | 119,732,640 | 44,121,478 |
| 2025 | 50,032,220 | 6.25% | 3,127,014 | 25.76 | 80,551,874 | 40.00 | 125,080,550 | 44,528,676 |
| 2026 | 50,354,720 | 6.50% | 3,273,057 | 26.28 | 86,015,933 | 40.00 | 130,922,272 | 44,906,339 |
| 2027 | 50,950,700 | 6.75% | 3,439,172 | 26.80 | 92,169,816 | 40.00 | 137,566,890 | 45,397,074 |
| 2028 | 51,864,880 | 7.00% | 3,630,542 | 27.34 | 99,259,007 | 40.00 | 145,221,664 | 45,962,657 |
| 2029 | 52,603,620 | 7.25% | 3,813,762 | 27.89 | 106,365,835 | 40.00 | 152,550,498 | 46,184,663 |
| 2030 | 53,577,140 | 7.50% | 4,018,286 | 28.44 | 114,280,040 | 40.00 | 160,731,420 | 46,451,380 |

The Company previously estimated compliance costs for the APS were approximately $40 million in the most recent few years. Starting 2023, as a result of AEC shortage conditions as a result of

[8] Department of Energy Resources, "Alternative Energy Portfolio Standard 2020 Minimum Standard Review Summary," July 2021, at 4.

electrification and AEC supply decrease (and not including a Minimum Standard increase of 2%), the annual costs will be over $70 million per year when compliance costs are at the current regulations' ACP rates. If the Straw Proposal's ACP rates of $40 are approved, compliance costs in 2023 are approximately $114 million, creating $43 million of windfall of profits to APS Generation Units. From 2023 through 2030, this results in significant unneeded payments by customers of $361 million.

The table below shows the increase in costs due to the ACP rate increase and the Minimum Standard percentages increase from current levels in 2023 per the Straw Proposal.

**Table 7: Estimated Compliance Costs from Straw Proposal Percentage Increases Plus Straw Proposal ACP Rate Increases: 2023 - 2030**

| | Compliance Load Obligation (MWH) | Proposal Percentage | Proposed AECs Needed | Current ACP Rate (in $) | Proposed Costs at Current ACP (in $) | Proposed ACP Rate (in $) | Proposed Costs with New ACP (in $) | Increased Costs (in $) |
|---|---|---|---|---|---|---|---|---|
| 2023 | 49,488,700 | 7.50% | 3,711,653 | 24.76 | 91,900,516 | 40.00 | 148,466,100 | 56,565,584 |
| 2024 | 49,888,600 | 7.75% | 3,866,367 | 25.26 | 97,664,418 | 40.00 | 154,654,660 | 56,990,242 |
| 2025 | 50,032,220 | 8.00% | 4,002,578 | 25.76 | 103,106,399 | 40.00 | 160,103,104 | 56,996,705 |
| 2026 | 50,354,720 | 8.25% | 4,154,264 | 26.28 | 109,174,068 | 40.00 | 166,170,576 | 56,996,508 |
| 2027 | 50,950,700 | 8.50% | 4,330,810 | 26.80 | 116,065,695 | 40.00 | 173,232,380 | 57,166,685 |
| 2028 | 51,864,880 | 8.75% | 4,538,177 | 27.34 | 124,073,759 | 40.00 | 181,527,080 | 57,453,321 |
| 2029 | 52,603,620 | 9.00% | 4,734,326 | 27.89 | 132,040,347 | 40.00 | 189,373,032 | 57,332,685 |
| 2030 | 53,577,140 | 9.25% | 4,955,885 | 28.44 | 140,945,382 | 40.00 | 198,235,418 | 57,290,036 |

Starting 2023, as a result of AEC shortage conditions as a result of electrification, a demand increase of 2% to the Minimum Standard, and AEC supply decrease, the annual costs will be approximately $92 million per year when compliance costs are at the current regulations' ACP rates. If the Straw Proposal's ACP rates of $40 are approved, compliance costs in 2023 are approximately $148 million, creating a $57 million windfall of profits to APS Generation Units. From 2023 through 2030, this results in a massive profit windfall of $457 million.

Under all scenarios, customers' bills will increase to compensate these units.

To the extent that certain technologies require the AEC price to be higher than the $15 AEC price noted in the DOER's APS Review, the DOER should consider a small carve-out of the APS's Minimum Standard specific to these technologies or develop multiplier factors for such technologies to reward specific types of technologies with more AECs, which would also reduce the expected shortfall. Either of these approaches would serve two purposes: it would incentivize targeted technologies while also protecting customers from unreasonably high prices for the entire APS compliance obligation.

Thank you again for the opportunity to provide comments on the APS during this review.

Sincerely,

Ian Springsteel

Director, U.S. Retail Regulatory Strategy