Distributed Energy Resource Interconnection Cost Allocation:
An Evaluation of Alternatives and Recommendations for Consideration

A Report of the Grid Mod Advisory Group
Per RSA 12-P:16

Submitted to NH Department of Energy
Commissioner Jared Chicoine

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Table of Contents

Executive Summary

Introduction

The NH Grid Modernization Advisory Group (GMAG) was convened in November 2023 following passage of Senate Bill 166[1]. The GMAG was formed to "consider and provide recommendations to the department and the legislature on issues including but not limited to:

(1) Grid modernization as defined in RSA 374-F:2;

(2) Transactive energy and distributed energy resources including advanced meter infrastructure (3); Settlement of appropriate price signals for transactive energy at the distribution system level for distributed energy resources;

(4) Appropriate customer and distributed resources access to temporal price signals;

(b) The GMAG shall review different cost structures that enable a reasonable portion of costs of distributed generation and storage interconnections to be shared by entities that interconnect future distributed generation or storage to the distribution grid to the extent that such subsequent interconnection is enabled by the investment, or costs incurred by the prior entity or entities that interconnect. The GMAG shall provide recommendations to address this issue by September 1, 2024".

One of the first actions of the GMAG was to create a subcommittee to address item (4)(b), to review different cost structures, which is subject of this report. The GMAG convened the Interconnection Subcommittee in the spring of 2024 to consider the challenges and opportunities related to interconnect of distributed energy resources (DERs) in New Hampshire. Based on the subcommittee conversations and engagement with the entire GMAG, the subcommittee made a series of recommendations that were considered and adopted by the full GMAG at their August 27, 2024 meeting.

Background

DERs are small-scale energy systems, including solar photovoltaic (PV) systems, wind turbines, and energy storage systems, with smaller systems typically located close to the point of consumption. These technologies allow consumers to generate, store, and sometimes sell electricity back to the grid, contributing to a more resilient and efficient energy system. The integration of DERs into the grid supports the shift toward a decentralized and sustainable energy future by reducing reliance on large power plants, lowering greenhouse gas emissions, and providing backup power during outages. Effective DER interconnection, the process of safely and reliably connecting and operating these systems to the grid, is crucial for maximizing their benefits while maintaining grid stability.

The costs associated with DER interconnection, which include application fees, grid impact studies, and particularly with necessary infrastructure upgrades, can be a significant barrier to the widespread adoption of these technologies. High interconnection costs can deter projects and create disparities in the growth of DERs across different regions.

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[1] SB166 (2023). Senate Bill 166, "*An act relative to electric grid modernization*", https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2023&id=1056&txtFormat=html.

Throughout the country the predominant method for allocating DER interconnection cost is the "cost-causer pays" principle. This principle ensures that the costs associated with interconnecting DERs to the grid are primarily borne by the entities that cause those costs—typically the DER owners or developers. Costs directly attributable to a specific DER project (such as upgrades to local infrastructure required solely for that project) are allocated to the DER owner.

The cost-causer pays principle, where the DER owner bears the costs of necessary grid upgrades, is common but can viewed as inequitable, especially when the upgrades benefit existing and future utility customers and/or future interconnecting DER. To address these challenges, alternative cost allocation schemes and streamlined interconnection processes are being considered and implanted in some areas of the country to promote fairer cost distribution, enhance grid reliability, and encourage broader adoption of sustainable energy solutions.

Future trends influencing DER interconnection will be shaped by the widespread electrification of buildings and the transportation sector, both of which will significantly increase demand for grid connectivity and flexibility. As more homes and businesses transition to electric heating, cooling, and appliances, alongside the growing adoption of electric vehicles (EVs), the grid will need to accommodate a surge in electricity demand and consumption. This shift will require enhancements to grid infrastructure, such as increased capacity and advanced grid management technologies, to efficiently integrate a diverse array of DERs while maintaining stability and reliability.

Cost allocation for DER interconnection costs beyond the traditional utility cost causation model is relatively new. There are only a handful of states that have developed formal methodologies, rules, and processes. Moreover, most are in the early stages of implementation after several years of development and significant issues remain. During the Interconnection Cost Structure subcommittee investigation, the subgroup considered how other states are approaching the issue of cost allocation for DER interconnections.

Summary and Recommendations

There is significant interest in New Hampshire in developing reasonable cost allocation methodologies for DER interconnection, as seen in states that have already spent years refining these processes. However, the complexity and need for individual regulatory review means it will take time to assess the impacts fully. The GMAG emphasizes that keeping cost allocation methodologies simple will increase the likelihood of success in New Hampshire.

As mandated by SB191[2], the New Hampshire Department of Energy (NHDOE) will begin an investigative and rulemaking proceeding by September 26, 2024, to establish uniform procedures for DERs, including addressing cost responsibilities. The GMAG recommends creating a DER cost allocation working group as part of this proceeding and advocates for robust participation from GMAG members. Additionally, utilities should provide transparent information on planned system upgrades and develop simple mechanisms for DER access fees, line extensions, and cost-sharing for group studies and substation upgrades. More detailed recommendations from GMAG are included in the Summary and Conclusion section.

[2] SB391 (2024). Senate Bill 391, "*An act relative to electric grid interconnection for certain customer generators*", https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2024&id=2095&txtFormat=html.

The current PUC/NHDOE 900 rules apply to net-metered customer-generators under 1 MW, with minimal requirements for interconnection processes or costs beyond basic application processing. The GMAG suggests that any agreed-upon cost allocation methodologies should be included in these rules and that the rules should also address non-net-metered DER interconnections and those exceeding 1 MW. This approach will help ensure a fair and structured framework for DER integration in New Hampshire.

Conclusion

Addressing the complexities of interconnection cost allocation for DERs is essential for fostering a resilient and sustainable energy system. A balanced approach is needed to ensure costs are fairly distributed among stakeholders without hindering the adoption of DERs, considering the diverse needs of regions, project sizes, and existing grid infrastructure. Reducing interconnection barriers can lower energy costs, reduce greenhouse gas emissions, and enhance grid reliability, requiring collaboration among regulators, utilities, and DER developers. Striking the right balance in cost allocation will be crucial to realizing the full potential of DERs in a cleaner energy future.

Distributed Energy Resource Interconnection Cost Allocation: An Evaluation of Alternatives and Recommendations for Consideration

A Report of the Grid Mod Advisory Group Per RSA 12-P:16

Introduction

Distributed Energy Resources (DERs) are small-scale energy systems, such as solar panels, wind turbines, and energy storage systems, located close to the point of consumption. These technologies allow consumers to generate, store, and sometimes sell electricity back to the grid, contributing to a more resilient and efficient energy system. The integration of DERs into the grid supports the shift toward a decentralized and sustainable energy future by reducing reliance on large power plants, lowering greenhouse gas emissions, and providing backup power during outages. Effective DER interconnection, the process of safely and reliably connecting these systems to the grid, is crucial for maximizing their benefits while maintaining grid stability.

The costs associated with DER interconnection, which include application fees, grid impact studies, and necessary infrastructure upgrades, can be a significant barrier to the widespread adoption of these technologies. High interconnection costs can deter smaller projects and create disparities in the growth of DERs across different regions. The "cost-causer pays" principle, where the DER owner bears the costs of necessary grid upgrades, is common but often viewed as inequitable, especially when the upgrades benefit future grid users as well. To address these challenges, alternative cost allocation schemes and streamlined interconnection processes are being considered to promote fairer cost distribution, enhance grid reliability, and encourage broader adoption of sustainable energy solutions.

The most effective alternative for DER interconnection cost allocation often depends on the specific context and objectives of the stakeholders involved, such as utilities, DER owners, regulators, and consumers. It was and is apparent the issue of interconnection cost allocation is extremely complicated and will require robust and comprehensive processes among stakeholders to properly develop. Further, statutory changes will likely be required as well as formal proceedings with the New Hampshire Department of Energy (NHDOE) and Public Utilities Commission (PUC).

GMAG Background and Recent History

The NH Grid Modernization Advisory Group (GMAG) was convened in 2024 following passage of Senate Bill 166[3] in 2023. The GMAG was formed in order to investigate and consider issues

[3] SB166 (2023). Senate Bill 166, "*An act relative to electric grid modernization*", https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2023&id=1056&txtFormat=html.

related to the challenges and opportunities that the NH electric sector faces now and, in the future, based on environmental changes, demographic shifts, and technological innovation.

> RSA 12-P:16, Grid Modernization Advisory Group (eff. 10/07/2023)
>
> II, (b) The GMAG shall review different cost structures that enable a reasonable portion of costs of distributed generation and storage interconnections to be shared by entities that interconnect future distributed generation or storage to the distribution grid to the extent that such subsequent interconnection is enabled by the investment, or costs incurred by the prior entity or entities that interconnect. The GMAG shall provide recommendations to address this issue by September 1, 2024.

The GMAG convened the Interconnection Subcommittee in the spring of 2024 in order to consider the challenges and opportunities related to interconnect of DERs in New Hampshire. Based on the subcommittee conversations and engagement with the entire GMAG, the subcommittee made a series of recommendations that were considered and adopted by the full GMAG.

Overview of DER and Interconnection Costs

Distributed Energy Resources

Distributed Energy Resources (DERs) are small-scale electricity generation and storage systems located close to the point of consumption. They include technologies such as solar panels, wind turbines, energy storage systems (like batteries), combined heat and power systems, and electric vehicles that can supply power back to the grid. DERs are typically connected to the local distribution grid, enabling consumers to generate, store, and potentially sell electricity back to the utility. These resources contribute to a more resilient and efficient energy system by reducing the need for large, centralized power plants and enhancing the flexibility of the grid.

The integration of DERs into the energy grid supports the transition to a more sustainable and decentralized energy system. They offer numerous benefits, such as reducing transmission and distribution losses, lowering greenhouse gas emissions, and reducing peak demand and consumer energy costs. Additionally, DERs, if configured to operate in islanded mode, can provide backup power during outages, increasing the overall resilience of the electric supply system. As technology advances and regulatory frameworks evolve, DERs are becoming increasingly important in achieving energy security, lowering carbon emissions, and meeting the growing energy demands in a sustainable manner.

DER Interconnection

DER interconnection refers to the process of connecting small-scale energy systems, like solar panels, wind turbines, and batteries, to the existing electrical grid. This process involves technical, regulatory, and procedural steps to ensure that DERs can safely and reliably supply power to the grid. Key considerations include the capacity of the local distribution grid to safely and reliably accommodate additional power flow, the compatibility of DER systems with grid standards, and the protection of the grid, distribution customers and DER owners from potential issues such as voltage violations, power quality fluctuations, and equipment damage.

Effective DER interconnection is crucial for maximizing the benefits of distributed energy while maintaining safe, reliable grid operation. It requires coordination between utility companies, DER owners, and regulatory bodies to establish clear guidelines and standards. As the adoption of DERs grows, improving interconnection processes can facilitate greater integration of renewable energy, enhance overall grid efficiency, and support the transition to a more decarbonized and sustainable energy system.

DER Interconnection Costs

The costs associated with DER interconnection encompass a range of expenses required to connect small-scale energy systems, like solar panels and batteries, to the electrical grid. These costs typically include application fees, grid impact studies, and any necessary upgrades to the distribution system to safely and reliably accommodate the new resources. Depending on the complexity and scale of the DER system, costs may also involve equipment installation, metering, and potential modifications to ensure compliance with safety and technical standards.

DER interconnection costs can vary widely based on factors like location, the size and type of the DER system, and the existing grid infrastructure's capacity to handle additional demand. High interconnection costs can be a barrier to the widespread adoption of DERs, especially for smaller or individual projects. However, as technology advances and regulatory frameworks evolve, efforts are being made to streamline the interconnection process and reduce costs, making it easier for more people and businesses to contribute to a decentralized and sustainable energy future.

Current NH Methods of DER Interconnection Cost Allocation

The predominant form of DER interconnection in cost allocation is the "cost-causer pays" principle. This principle ensures that the costs associated with interconnecting DERs to the grid are primarily borne by the entities that cause those costs—typically the DER owners or developers. Costs directly attributable to a specific DER project (such as upgrades to local infrastructure required solely for that project) are allocated to the DER owner.

Example: If a new solar farm requires upgrades to a nearby substation, the solar farm owner pays for these upgrades. The solar farm pays for these upgrades and any excess capacity that is created by the upgrades due to use of standard size equipment and unused by the solar farm can be used by future DER interconnections and load customers."

Challenges in DER Interconnection Cost Allocation

The high costs of DER interconnection present significant challenges to the development and widespread adoption of Distributed Energy Resources (DERs). These costs, which include application fees, grid impact studies, and necessary upgrades to the grid infrastructure, can deter smaller projects and individual consumers from investing in DER systems like solar panels and batteries. The financial burden is often more pronounced in regions with older grid infrastructure or complex interconnection processes, making it difficult for DER developers to justify the investment, particularly when the potential return on investment is uncertain. Cost causation is almost never a fully fair and equitable framework. Often the "cost causer" ends up paying 100% of the cost for upgrades that will benefit both future DER interconnections and grid customers through increased capacity and reliability.

Additionally, the variability of interconnection costs based on location and project size/type creates an uneven playing field, where some regions or larger projects can absorb these costs more easily than others. This disparity can slow the overall growth of DERs, limiting the potential benefits of increased renewable energy adoption, including reduced GHG emissions and reduced peak demand and energy costs. Addressing these challenges requires regulatory reform, incentives, and the development of standardized interconnection procedures to reduce costs and make DER deployment more accessible, ultimately supporting a more sustainable and decentralized energy future.

Alternative DER Interconnection Considerations

Developing alternative interconnection cost schemes for Distributed Energy Resources (DERs) requires careful consideration of fairness, transparency, and the long-term impact on the electric grid. One key consideration is how to equitably distribute the costs between the beneficiaries of grid upgrades: DER developers, end consumers and society at-large. Ensuring that cost allocation reflects the benefits and burdens of integrating DERs into the grid is essential for encouraging broader adoption without placing undue financial strain on any single group. This may involve creating tiered cost structures based on the size or location of the DER system or implementing cost-sharing mechanisms where grid upgrades benefit multiple stakeholders.

Another important consideration is the need to streamline the interconnection process while maintaining grid reliability and safety. Simplifying application procedures, standardizing technical requirements, establishing and enforcing utility timelines, and enhancing transparency around cost calculations can reduce uncertainty for developers and lower barriers to entry. Additionally, regulatory frameworks should incentivize innovative solutions, such as grid modernization efforts that promote flexible interconnections and grid services, enhance the capacity to integrate more DERs, or the development of virtual power plants (VPPs) and microgrids. These considerations are crucial for creating interconnection cost schemes that balance the need for infrastructure investment with the goal of promoting sustainable energy development.

Cost Allocation Alternatives

Cost allocation for DER interconnection costs beyond the traditional utility cost causation model is relatively new. There are only a handful of states that have developed formal methodologies, rules, and processes. Moreover, most are in the early stages of implementation after several years of development and significant issues remain.

During the investigation, the Cost Structure subgroup investigated how other states are approaching the issue of cost allocation for DER interconnections. Initial findings were presented to the GMAG on May 16th. Some of the subgroup members were familiar with cost allocation methodologies for Massachusetts and New York and provided details in presentations and corresponding discussion. Details on cost allocation methodologies are provided in the following section **Cost Allocation Methodologies and Issues**. A high-level summary of options investigated is provided in **Table 1** below.

Table 1 – Summary of Cost Allocation Methodologies

Type	Also Known As	Description	State(s)	Cost Allocation	Cost Recovery
Cost Causation		Entity causing need of system upgrades are responsible for payment of costs.	All	Interconnecting customer	Interconnecting customer
Limited Generation Profile (LGP)	Flexible IX (Interconnection)	Schedules limit DER energy and microgrids can send based on grid constraints.	CA	Avoids cost for interconnecting customer. Does not allocate to others.	Interconnecting customers
Basic Cost Sharing for Line Extention	Enhanced Line Extension	Expand upon existing Line Extension policies. Interconnecting Customer pays upgrades and is reimbursed by other future customers as they use the expanded capacity.		Interconnecting customer and subsequent customers. Limit to X years.	First customer(s) pay for upgrades. Reimbursed over time of others join.
Basic Cost Sharing for Substation Upgrades	Sub-Station Upgrades for 3VO or other conditions.	Ground Fault Over Voltage (GFOV) protection often requires system upgrades at the Substation. If a System Impact Study identifies significant substation investments are required other potential interconnecting customers can share those costs.	VT	Interconnecting customer and subsequent customers. Limit to X years. VT has a one-time Transmission Ground-Fault Overvoltage (TFGOV) fee.	First customer(s) pay for upgrades. Reimbursed over time of others join. VT from all interconnecting customers.
Market Based Grid Access Fee	Grid Access Charge (GAC)	Utility and Stakeholder process, overseen by state regulators, develop fees and rate structures.	CA. Consider-ed in others	Access fees paid by interconnecting customers. Fees vary by need as determined by utility, stakeholders and regulators.	Access fees and portion from utility rate base
Multi-Beneficiary Cost Sharing	Provisional System Planning Program for Capital Improvement Projects (CIP) in MA. System Planning and Group Studies Integrated Distribution Planning (IDP)	Utilities forecast where DERs will be sited and plan upgrades for those locations. Locations shown on hosting capacity maps. Market driven studies can also identify projects.	MD, MA, NM, NY	Proportionally allocate costs (typically $/kW of nameplate) to new customers after first interconnection customer pays fair share of cost.	Portion of interconnection costs recovered from customers in rate base.

Cost Allocation Methodologies and Issues

The following interconnection options, drawn from Table 1, above provide high level description of the cost allocation methodology, the mechanism of recovery, the pros and cons and critical issues/considerations that need to be considered when implementing.

The following are not included as recommendations, but as references for policymakers and stakeholders.

Option 1: Cost Causation (AKA Cost Causer Pays)

Overview:

- Historical standard in utility industry.
- Entity causing need for system upgrades responsible for full cost.

Cost Responsibility and Recovery/Allocation:

- Interconnecting customer(s).

Pros:

- Ratepayers are not burdened by cost.

Cons:

- Does not encourage DER, especially as DER penetration increases.
- DERs almost always pay for more capacity than they require, effectively subsidizing other beneficiaries including other DERs and grid customers.
- Creates bottlenecks on the grid where a single large upgrade cannot be borne by any single DER but multiple DERs together could pay for the upgrade if an alternative cost allocation methodology was used.
- Eventually leads to queue stagnation and withdrawals

Key issues to address:

- N/A

Option 2: Limited Generation Profile

Overview:

- DER agrees to schedules or directives to limit output based on grid constraints.
- Also known as Flexible IX (Interconnection).

Cost Responsibility and Recovery/Allocation:

- Minimizes system upgrades needed by the utility and reduces interconnection cost to the developer.

Pros:

- Potential to lower cost of interconnection for developer and potentially ratepayers.
    - Potential for enhanced controls that will need to be shared by ratepayers.
- Potential to remove interconnection upgrades allowing DERs to interconnect on a faster schedule.
- Simple.

Cons:

- Requires robust monitoring and control infrastructure.
- Continuingly changing schedules.
- Lower production and revenue for DER projects when schedule requires limited output.
- Does <u>not</u> increase hosting capacity and eventually leads to queue stagnation

Key issues to address:

- Systems and resources needed by utilities and customer generators (c-g).
- Enforcement and control.

Option 3a: Basic Cost Sharing for Line Extension

Overview:

- Expand upon existing Line Extension policies.
- Interconnecting Customer pays for upgrades and is reimbursed by other future customers as they use the expanded capacity.

Cost Responsibility and Recovery/Allocation:

- Interconnecting customer and subsequent customers. Limit to 5? years.
- First interconnection customer pays. Reimbursed if others join.

Pros:

- Potential to lower cost of interconnection for developer(s).
- Relatively simple.

Cons:

- Requires utilities to manage and distribute funds to multiple organizations over multiple years; potentially complex and intractable.
- Could result in prohibitively high initial costs for interconnecting customer, uncertain costs for future customers, and uncertain reimbursements

Key issues to address:

- Allocate cost by $/kW and distance of specific line upgrades used.
- Number of years for recovery.

Option 3b: Basic Cost Sharing for Substation Upgrades

Overview:

- If significant substation upgrades are identified during a System Impact Study (SIS).
    - i.e. requirements to meet 3VO, transformer capacity upgrades, or other conditions.
    - Utility to identify upgrade requirements and make known to developers so the potential exists to share system upgrade costs.

Cost Responsibility and Recovery/Allocation:

- Interconnecting customer(s) and subsequent customers. Limit to 5? years.
- First interconnection customer pays. Reimbursed if others join.

Pros:

- Allows other developers to know about potential project(s) for cost sharing.
- Potential to lower cost of interconnection for developer(s).
- May be relatively simple.

Cons:

- Requires utilities to manage and distribute funds to multiple organizations over multiple years; potentially complex and intractable.
- Could likely result in prohibitively high initial costs for interconnecting customer, uncertain costs for future customers, and uncertain reimbursements

Key issues to address:

- Allocate cost by $/kW or other factor(s).
- Number of years for recovery.
- How to communicate identified upgrades. i.e. Hosting Capacity Map links, etc.

Option 4: Market-Based Grid Access Fees

Overview:

- Utility and Stakeholder process, ***overseen by state regulators***, to develop fees and rate structures for customer-generator and storage grid access.
    - Note: VT has a one-time Transmission Ground-Fault Over Voltage (TGFOV) fee.

Cost Responsibility and Recovery/Allocation:

- Access fees paid by interconnecting customers. Portion *potentially* by ratepayers.

- The fees are paid into a pool with the utility and those fees are used to offset interconnection costs. It is considered not as fair or equitable, but much easier to implement.
- Fees vary by need as determined by utility, stakeholders and regulators.

Pros:

- Creates market price signals to drive developers to appropriate locations on utility system.
- Effective at recovering utility costs.
- Easy to understand.

Cons:

- May reduce incentive to interconnect, especially for storage.
- Time and effort to evaluate fee structures
- Higher operating costs for DERs.

Key issues to address:

- Determine if this is desirable for NH.
- Developing appropriate access fees across the distribution system and updating those schedules as DERs interconnect and upgrades are built.

If it has potential, find examples to use as a basis.

Option 5: Multi-Beneficiary Cost Sharing

Overview:

- Developers can share in the cost of system studies and/or upgrades.
- Utilities forecast where DER's may be sited and plan upgrades for those locations.
    - Locations shown on hosting maps.
- Market driven studies can also identify potential system upgrade projects.

Cost Responsibility and Recovery/Allocation:

- Proportionally allocate costs (typically $/kW of nameplate) to new customer(s) after first interconnection customer(s) pays fair share of cost or minimum threshold.
- A portion of costs may be able to be recovered from ratepayers.
    - If benefits to all customers can be demonstrated.

Pros:

- Utilities can apply portions of costs that benefit all customers to their rate base.
- Market driven studies and projects also considered.

- By forecasting load growth and electrification, utilities and ratepayers can benefit from appropriately planned grid upgrades that benefit both DERs and the grid and its ratepayers.
- Relatively simple cost structure with fixed CIP fee and cost certainty for current and future projects
- Reduced cost for developers as costs are shared with ratepayers; ratepayers also benefit by having developers partially fund projects that increase capacity and reliability

Cons:

- Cost tracking and crediting efforts may be needed by utility and regulators.
- Individual dockets for each CIP in the case of MA.
- If planned DG is not built, ratepayers pay for unnecessary upgrades.
- Time consuming. Will take considerable effort to develop for NH, but NH can learn from surrounding jurisdictions such as CT
- May be too complicated or not appropriate for NH at this time.

Key issues to address:

- Complexity of the structure design, but models in other jurisdictions may simplify the development and implementation process.

Option 6: Activity-Based Costing (ABC)

Overview:

- A cost accounting method used to allocate costs more accurately based on the actual activities involved in the process. In the context of DER interconnection, ABC helps utilities and regulators determine the specific costs associated with connecting renewable energy sources, like solar panels or wind turbines, to the grid.

Cost Responsibility and Recovery/Allocation:

- ABC breaks down the entire interconnection process into specific activities, such as engineering reviews, site inspections, and administrative tasks.
- It then assigns costs to each activity based on the resources consumed.

Pros:

- **Accuracy**: Unlike traditional costing methods, ABC provides a more accurate reflection of the costs incurred for interconnection by considering the complexity and time required for each activity.
- **Fair Pricing**: By using ABC, utilities can set more equitable fees for DER interconnection, ensuring that customers are charged based on the actual costs incurred rather than a flat rate.
- **Regulatory Compliance**: ABC can help utilities comply with regulatory requirements by providing a transparent and justifiable cost structure.

Cons:

- Complex, requires time and effort to develop fee schedules, requires significant ongoing compliance
- There are not many if any actual examples of this working in practice.

Key issues to address:

- Complexity

Future Trends

Future trends influencing DER interconnection will be shaped by the widespread electrification of buildings and the transportation sector, both of which will significantly increase demand for grid connectivity and flexibility. As more homes and businesses transition to electric heating, cooling, and appliances, alongside the growing adoption of electric vehicles (EVs), the grid will need to accommodate a surge in electricity consumption. This shift will require enhancements to grid infrastructure, such as increased capacity and advanced grid management technologies, to efficiently integrate a diverse array of DERs while maintaining stability and reliability.

Additionally, the integration of DERs will be influenced by the need for greater grid flexibility and resilience in response to changing energy consumption patterns. The future energy landscape will likely see the rise of modernized grids, where advanced technologies enable dynamic management of bi-directional energy flows and real-time balancing of supply and demand. Regulatory frameworks and interconnection standards will need to evolve to support these developments, ensuring that the integration of DERs can keep pace with the growing electrification of buildings and transportation, ultimately contributing to a cleaner, more sustainable energy system.

Summary and Recommendations

There is considerable interest in developing reasonable cost allocation methodologies for interconnection in NH. As discussed, states that are further along have spent several years developing methodologies and processes. However, it will take time to evaluate the impacts. Moreover, some are complicated and require individual regulatory review. The GMAG believes keeping cost allocation methodologies simple will greatly increase the likelihood of success in NH.

As directed in SB191[4] (effective 07/26/2024), the DOE will open an investigative and rulemaking proceeding for the purposes of setting uniform procedures for DER no later than September 26, 2024. SB391 requirements include addressing "cost responsibilities" of DER projects. Further, the bill directs the NHDOE to utilize the comments the NHDOE received as part of the investigatory proceeding IP 2022-001. The recommendations from IP 2022-001

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[4]SB391 (2024). Senate Bill 391, "*An act relative to electric grid interconnection for certain customer generators*", https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2024&id=2095&txtFormat=html.

report[5] include the creation of Working Groups to address the various interconnection issues. The GMAG strongly recommends the creation of a cost allocation working group for this new proceeding.

Given the complexity and multitude of issues that must be addressed and resolved the GMAG believes the most appropriate next step to address interconnection cost allocation is for the GMAG members to participate in the upcoming investigative and rulemaking proceeding.

After careful consideration and discussion, the GMAG recommends the following:

- Creation of a DER cost allocation working group as part of the upcoming NHDOE investigating and rulemaking proceeding.
- Robust engagement from GMAG members in the upcoming rulemaking proceeding.
- To aid DER developers (and customers) in developing appropriate project locations for the purpose of maximizing system benefits and reducing project costs, utilities should post/link high-level planned system upgrade projects on their websites in convenient locations such as hosting maps.
    - Privacy considerations and regulatory limitations may impact what will be able to be posted.
    - Links to relevant planning documents should also be provided.
- Utilities should develop simple DER access fees:
    - For example, smaller (<25 kW) interconnection projects a $/kW to pay for upgrades such as new, higher capacity pole top transformers.
        - Similar approaches can be made for larger DER
- Utilities should develop simple line extension policies for DER projects, with a 5 (or 10) year look-back.
    - Simple $/kW payment.
    - Projects that come after upgrades complete to pay their pro-rated share of the upgrades based on capacity and distance of the line extension or upgrade utilized.
    - Recommend development of details during upcoming interconnection and rulemaking proceeding.
- Utilities should develop simple mechanism(s) for sharing DER Group Study costs and disseminating the study results.
    - Utilities should advertise planned group studies so others can see upcoming activity and participate.
        - Fees and other details can be provided as necessary.

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[5] NHDOE (2023). IP 2022-001 Investigative Proceeding Relative to Customer-Generator Interconnection, NH Department of Energy, https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/inv-ip-2022-001-doe-final-report-12-05-23.pdf.

    - Utilities to post (link) to study results in convenient locations (such as hosting capacity maps) on their websites.
        - Privacy concerns and other issues may result in limitations regarding the level of detail and what information can be provided.
- Utilities to develop simple mechanism(s) to share costs for substation upgrades.
    - Utilities to post planned substation upgrades on hosting maps.
    - $/kW based on project size, with published rate limits.
    - Projects that come after upgrades complete to pay their pro-rated share of the upgrades based on capacity of the upgrade used.

PUC/NHDOE Rules

The current PUC/NHDOE 900 rules for DER interconnections apply to net-metered customer-generators < 1,000 kW (or 1 MW). Moreover, there are few requirements addressing interconnection processes for the customer-generators or the utilities and nothing addressing interconnection costs beyond basic application processing.

Any cost structure/allocation methodologies, if they are ultimately agreed upon for implementation, should be included in PUC/NHDOE rules. The issues of non-net metered DER interconnections as well as those > 1 MW should also be addressed.

Conclusion

Addressing the complexities of interconnection cost allocation for DERs is crucial for advancing a more resilient and sustainable energy system. The solutions to these challenges are not straightforward, as they must balance the need to fairly distribute costs among stakeholders while encouraging the broader adoption of DERs. Ensuring that interconnection costs do not become prohibitive requires a nuanced approach, one that considers the varying needs of regions, project sizes, and existing grid infrastructure. By carefully calibrating cost allocation methods, we can create an environment where DERs can thrive without compromising grid safety and reliability or placing undue financial burdens on any single group.

Despite the challenges, the potential benefits of reducing interconnection hurdles are significant. By fostering the development of DERs, we can lower overall energy costs, contribute to GHG emissions reduction, and help build a more reliable and resilient energy infrastructure capable of meeting future demand and electrification growth. This requires a concerted effort from regulators, utility companies, and DER developers to innovate and adapt to the evolving energy landscape. Ultimately, striking the right balance in interconnection cost allocation will be key to unlocking the full potential of DERs, enabling a transition to a cleaner, more sustainable energy future.