Community Solar Garden Study, 2024

December 15, 2024

Prepared for Minnesota Department of Commerce
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Pursuant to Laws of Minnesota (2023), Ch. 60, Art. 12, Sec. 73
RFP COMM-GFO1-20240528
Contract Number: 253483

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As requested by Minnesota Statutes § 3.197: This report cost approximately $271,910.00 to prepare, including staff time, printing and mailing expenses.

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Pursuant to the Laws of Minnesota 2023, Chapter 60, Article 12, Section 73, the Minnesota Department of Commerce hired a third party to conduct a study of Minnesota's community solar garden program, as described in Minnesota Statutes § 216B.1641. Following a competitive bidding process, the Department of Commerce selected a project team led by the Great Plains Institute (GPI), with the National Association of State Energy Officials (NASEO) Synapse Energy Economics, Inc. (Synapse) providing subcontracting expertise. An overview of all three organizations is provided below. Collectively, throughout this report, the project team is referred to as the "report authors."

Great Plains Institute (GPI)

A nonpartisan, nonprofit organization, the Great Plains Institute (GPI) accelerates the transition to net-zero carbon emissions for the benefit of people, the economy, and the environment. Working across the US, we combine a unique consensus-building approach, expert knowledge, research and analysis, and local action to find and implement lasting solutions. Our work strengthens communities and provides greater economic opportunity through the creation of higher-paying jobs, expansion of the nation's industrial base, and greater domestic energy independence while eliminating carbon emissions.

National Association of State Energy Officials (NASEO)

NASEO is the only national nonprofit association for the 56 governor-designated State and Territory Energy Offices. Formed by the states in 1986, NASEO facilitates peer learning among state energy officials, serves as a resource for and about State Energy Offices, and advocates for the interests of the State Energy Offices to Congress and federal agencies.

Synapse Energy Economics, Inc. (Synapse)

Synapse Energy Economics is a research and consulting firm focused on the intersection of energy, economics, and the environment. Since 1996, they've provided rigorous technical, quantitative, and policy analysis to help public interest and governmental clients improve planning, policies, and decision-making in the energy sector.

Glossary, Abbreviations, and Universal Terms

Acronym	Term
ARR	Applicable Retail Rate
BDs	Business days
BCA	Benefit-cost analysis
BCR	Benefit-cost ratio
BESS	Battery energy storage systems
Commission	Minnesota Public Utilities Commission
ComEd	Commonwealth Edison Company
CSG	Community solar garden
COMAR	Code of Maryland Regulations
CO PUC	Colorado Public Utilities Commission
DER	Distributed energy resource
DERMS	Distributed Energy Resource Management Systems
Commerce	Minnesota Department of Commerce
DG	Distributed generation
DSES	Distributed Solar Energy Standard
EPC	Engineering, Procurement, and Construction
Flex IX	Flexible Interconnection
GPI	Great Plains Institute
GW	Gigawatt
IC	Interconnection/Interconnecting Customer
ICC	Illinois Commerce Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-owned utility
kW	Kilowatt
LMI	Low- and moderate-income
MCAM	Maryland Cost Allocation Model
MN DIA	State of Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	State of Minnesota Distributed Energy Resource Interconnection Process
MPUC	Minnesota Public Utilities Commission

Acronym	Term
MW	Megawatt
NASEO	National Association of State Energy Officials
NYSERDA	New York State Energy Research and Development Authority
PSCo	Public Service Company of Colorado (a subsidiary of Xcel Energy)
PV	Solar Photovoltaic
RBPIA	Rate, bill, and participation impacts analysis
Report authors	GPI, NASEO, and Synapse
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SMART	Solar Massachusetts Renewable Target
SREC	Solar Renewable Energy Credit
Synapse	Synapse Energy Economics, Inc.
TIIR	Technical Interconnection and Interoperability Requirements
TPL	Technical Planning Limit
VOS	Value of Solar
Xcel	Xcel Energy

Executive Summary

Minnesota's community solar garden (CSG) program is one of the oldest operating community solar programs in the country. CSG programs allow consumers to purchase subscriptions to a centralized solar facility and receive credits on their electric bills for the energy produced. The CSG model offers subscribers the opportunity to benefit from solar energy without installing their own solar system—a process that is not only expensive for individual homeowners but also potentially infeasible for some customers due to the cost of investments for upgrading properties for solar panels. Minnesota CSG legislative policies and utility programs have contributed significantly to meeting the state's clean energy goals, resulting in over nine hundred megawatts of solar capacity from 2013 to 2024.

In 2023, the legislature modified Minnesota's CSG statutes. The changes to the CSG statutes aimed to increase residential customer participation in the CSG program with an emphasis on low- and moderate-income (LMI) customers and to manage and limit the annual deployment of CSGs. These changes came amidst a broader discussion and concerns about the costs of existing solar gardens, particularly gardens established in the early days of Minnesota's program.

The benefits of a CSG program, or any other means of meeting Minnesota's clean energy targets, need to be weighed against the costs and considered in the context of alternate ways of achieving the goals of an affordable, reliable, and equitable energy system. It is also appropriate to weigh the benefits to program participants in the context of impacts on other ratepayers and the electric system as a whole.

The statutory changes adopted in 2023 required that the Minnesota Department of Commerce (Department) administer the state's CSG program beginning in 2024. Program administration includes the following:

1. Collecting and evaluating community solar garden applications from subscriber organizations.
2. Auditing or verifying that project eligibility criteria have been met, as necessary.
3. Allocating community solar garden capacity to approved community solar gardens, subject to annual capacity limits.
4. Developing procedures to carry out the duties under the CSG legislation, including establishing procedures and a timeline to allocate community solar garden capacity.
5. Enforcing the consumer protections applicable to subscriber organizations.

The 2023 CSG legislation required a comprehensive study of the LMI-Accessible CSG Program (Laws of Minnesota 2023, Chapter 60, Article 12, Section 73; 2023 amendments to § 216B.1641). The legislation directed Commerce to provide this study to relevant legislative committees by December 15, 2024, and to include the following:

(1) a comparison of the program with similar programs operated in other jurisdictions, including a comparison of program structure, the manner in which applications are submitted and reviewed, how related infrastructure upgrades are prioritized and funded, and how regulations and penalties are structured;

(2) an analysis of the cost to ratepayers of operating the community solar garden program and a comparison with the cost to ratepayers of other potential options for encouraging adoption of solar electricity generation in this state; and

(3) *an analysis of how the community solar program impacts interconnection and infrastructure upgrade needs and challenges.*

Consistent with legislative requirements, this report aims to guide policymakers in achieving the objectives of Minnesota's LMI-Accessible CSG Program while addressing the challenges of program administration, implementation, and interconnection. First, the report provides a review of the LMI-Accessible CSG Program. Second, the report presents a cross-jurisdictional analysis comparing Minnesota's LMI-Accessible CSG Program to community solar programs in other jurisdictions with similar goals, in particular goals related to improving low- and/or moderate-income customers' access to community solar. Third, the report includes a benefit-cost analysis (BCA) to better understand potential CSG program cost impacts to participants, non-participants, and the state as a whole. Included is an analysis of both the relative merits of potential changes to the CSG program and alternatives to the CSG program. Finally, the report contains an interconnection analysis.

This report examines and assesses the CSG program that began in 2024 (Commerce's LMI-Accessible CSG program) and is forward looking. This report is not an analysis of the costs and benefits of the Xcel-only program that existed from 2013 until the end of 2023.

Ratepayer Benefits and Costs of the CSG Program

The report authors conducted a BCA for the CSG program and applied multiple industry cost tests in the methodology. The BCA finds that the LMI-Accessible CSG Program in Minnesota is cost-effective—meaning that its benefits exceed its costs. Over the study period, the CSG program is expected to deliver net benefits of $2.92 billion to Minnesota and $1.67 billion to CSG developers. The report authors clarify that this latter category is broad and encompasses financiers, and others engaged in the installation, operation, and maintenance of community solar gardens. For simplicity, the term "developer" is used throughout this report to stand in for this broad group.

Further, the BCA sought to understand the distribution of benefits and costs across specific populations, including LMI CSG subscribers, non-LMI subscribers, those who do not participate in the CSG program, and CSG developers, respectively. Based on the BCA, the expected benefits to both LMI and non-LMI subscribers are more modest. Over the study period, the CSG program is expected to deliver $139 million in net benefits to LMI subscribers and $116 million to non-LMI subscribers. Benefits are significantly higher than costs for Minnesota and CSG developers.

Additionally, the report authors performed a rate, bill, and participation impacts analysis (RBPIA) to examine the financial impacts of the CSG program on utility ratepayers. This analysis included subscribers and non-participants. Per the statute, all LMI customers are shielded from paying the net costs of the CSG program. All customers other than non-subscribing low-income customers experience a slight rate increase of about 2 to 3 percent. This is caused by the non-environmental avoided costs of solar generation being lower than average bill credit and the need to recover the above-market program costs collected through the fuel surcharge (which are not recovered from shielded non-subscribing low-income customers). For subscribing customers, bill credits more than offset this increase; thus, they experience a bill reduction.

Monthly bill impacts for subscribing customers range from around $7 to $10 per month in savings for LMI customers and $2 to $3 per month in savings for non-LMI customers. Non-subscribing low-income customers receive $1 to $2 per month in benefits due to protection from above-market program costs while receiving benefits from the avoided costs of solar generation. These bill impacts are equivalent to a 3 to 8 percent bill reduction for subscribing customers, about 1 percent bill reduction for non-subscribing low-income customers, and a 2 to 3 percent bill increase for non-participating non-LMI customers.

Report authors also performed sensitivity analyses regarding avoided costs, retail rate trends, and subscriber mix. The sensitivity analyses indicate that the program benefits are sensitive to avoided cost assumptions and that retail rates affect the dollar value of benefits to subscribers but not the relative proportion between benefits and costs.

Recommendations for CSG Program Improvements

The report considers program design options, offers recommendations based on community solar practices in other jurisdictions, evaluates the costs and benefits of the LMI-Accessible CSG Program, and identifies policy considerations that may impact broader policy and program outcomes. The report offers recommendations and considerations in two areas: (1) recommendations for Commerce based on the requirements outlined in laws and (2) policy considerations that may impact the implementation of the CSG program in Minnesota's broader energy policy context.

Recommendations for the Minnesota Department of Commerce

- **Commerce should expand LMI-Accessible CSG Program communications for consumers.** Most program communications in the early stages of 2024 are targeted toward developers. All stakeholders noted a need to create clear communications materials for potential subscribers. Utilities and developers noted a need for a trusted and unbiased source for prospective subscriber information.
- **Commerce can apply lessons learned from other jurisdictions.** Stakeholders and legislators expressed interest in learning from the approaches of other jurisdictions with LMI CSG programs. This report is the first step in that learning process. As CSG programs in other jurisdictions gain experience, Commerce can benefit from gathering practices to improve Minnesota's CSG program administration.
- **Commerce can consider implementing clear scoring criteria and weights for metrics** that may be difficult for applicants to quantify, such as resiliency or other community benefits.
- **Minnesota can consider increasing the LMI carve-out or providing additional incentives and/or preference to projects that serve a higher percentage of LMI subscribers.** As the Minnesota LMI-Accessible CSG Program matures and continues to compile data on the percentage of capacity each project is reserving for LMI subscribers, the collected data may support this action.
- **Commerce can seek to improve processes for income verification for LMI subscribers.** Such improvements should help to ease the burdens for low-income households and subscription organizations. Minnesota could consider providing additional pathways for verifying eligibility,

such as geo-eligibility, self-attestation, or automatic enrollment of beneficiaries of income-qualified programs.

- **Commerce can include additional program resources for consumers and update resources to best meet consumer needs.** Commerce can build from or adapt resources developed in other states and may need to hire staff or contract with a firm to ensure language accessibility and cultural relevance.
- **Commerce can develop additional consumer protections, such as marketing guidelines.** It could be important to clarify expectations for what might be considered a misleading claim or deceptive conduct. Commerce may also consider developing and publishing a process for evaluating and addressing complaints and potentially tasking personnel to monitor complaints and ensure compliance with the consumer protection requirements.

Policy Considerations for Interconnection and Grid Upgrades

- **Minnesota may wish to consider a more flexible approach to capacity limits to respond to changing market conditions.** *S*uch a change would not be in the direct purview of Commerce; rather, it would require the legislature to amend Minn. Stat. § 216B.1641, Subd. 3-14. Over time, capacity blocks or incentives may be phased out as market conditions become more favorable to solar.
- **Minnesota's interconnection policies and processes impact the CSG program's success and the interconnection of clean energy.** A large array of laws, rules, and regulations impact how clean energy resources connect to Minnesota's electricity delivery systems. The combined policies include existing laws and implementation by multiple state agencies—primarily Commerce and the Minnesota Public Utilities Commission (MPUC). In Minnesota, DER projects up to 10 MW in size are subject to the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) and compilation of a Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA). MN DIP establishes requirements pertaining to the interconnection application process, which interconnection process applies to a given project, as well as additional considerations, including those related to the interconnection queue, information transparency, and cost allocation.
- **The MPUC could consider adopting an enforcement mechanism to ensure that interconnection applications and studies are initiated and completed in a timely manner** and in accordance with the deadlines set forth in utility DER interconnection tariffs.
- **The MPUC could consider steps to reduce variability in cost estimates for grid upgrades.** To reduce the variability in cost estimates between system impact studies and facility studies, MPUC could require detailed itemized lists of project labor, equipment, and other costs across study stages.
- **Minnesota could adopt flexible interconnection regulations or launch pilots that would enable DER projects to connect to the grid under limited export agreements during certain constrained grid conditions.** This approach would use advanced technology such as smart inverters and/or battery energy storage to dynamically manage project power export when grid capacity was available and limit or prevent export during periods of constrained capacity. Either

a pilot or a rulemaking process would need to be initiated through the MPUC and implemented by the utility.

- **Minnesota could consider implementing a parallel process for small (residential scale) DERs.** These projects typically have minimal impact on grid infrastructure to expedite the interconnection process and help reduce the overall queue bottleneck.
- **Minnesota could consider implementing a pilot program for hosting capacity maps that provide timely data updates at the nodal level.** This dynamic data would provide actionable information to DER developers with more precise information about grid conditions, not only helping them avoid congested areas but also giving them greater visibility via nodal-level information in congested areas when selecting potential points of interconnection (POIs).
- **Minnesota could adopt a scenario-based modeling approach to proactively plan for and invest in future DER growth.** Under this approach, MPUC and the utilities would develop multiple growth scenarios for DERs and model potential grid constraints under various load profiles and future conditions to help utilities identify areas for potential grid infrastructure investments.
- **Minnesota could adopt a multi-beneficiary cost-sharing approach for DER interconnection,** where the costs of grid upgrades are shared among multiple beneficiaries rather than solely on the project that triggered the need for the grid upgrade. This approach would result in more equitable cost allocation among all the parties benefitting from the grid upgrade and could even include an element of proactive grid upgrade planning, where anticipated system investments are proactively made.

Analysis of Potential Alternatives for Solar Deployment

As directed by the 2023 legislation, the report authors modeled alternative options for encouraging solar adoption in Minnesota. The alternatives presented included the following:

1. A lower CSG subscription fee
2. Lower and higher annual installed CSG capacity limits
3. CSG bill credits based on Value of Solar (VOS)
4. An alternative utility or third-party solar procurement mechanism

Lowering CSG subscription fees provides the largest benefits to subscribers, including LMI subscribers. The report authors find that utility or third-party procurement that involves price discovery through competition or other means results in rate decreases for all customers, though this alternative does not provide direct financial benefits to a targeted group of customers (i.e., LMI subscribers). Both alternatives decrease the benefits to solar developers. The results of the BCA and RBPIA inform the following recommendations:

- **When Commerce engages in more detailed project review and applies its “Prioritization Scoring Rubric” to allocate program capacity to eligible facilities, consistent with Minn. Stat. § 216B.1641, Subd. 7b, Commerce should consider treating subscription rates as the primary selection criteria, prioritizing the allocation of capacity to those projects with the lowest subscription rates, and especially to those projects with the lowest subscription rates for LMI customers.** Per Minn. Stat. § 216B.1641, Subd. 7b, Commerce has wide latitude to prioritize the allocation of capacity to eligible projects based upon the scale of financial benefits that projects provide to LMI subscribers and other criteria. The BCA analysis results indicate that lower subscription rates result in increased benefits to LMI subscribers.

- **Minnesota can consider an alternative competitive procurement mechanism for distributed solar.** This procurement mechanism would help deploy distributed solar in Minnesota while avoiding bill impacts to Xcel Energy's customers. This can be achieved by expanding the amount of distributed solar to be procured through the competitive bidding process recently approved in Docket CI-23-403 for compliance with the Distributed Solar Energy Standard (DSES).

1.0 Introduction

Legislative Mandate and Context

During the 2023 legislative session, the Minnesota State Legislature passed substantial updates to the state's community solar garden (CSG) program, which was first enacted in 2013. Per Minn. Stat. § 216B.1641, a community solar garden is defined as "a facility (1) that generates electricity by means of a ground-mounted or roof-mounted solar photovoltaic device, (2) that is owned and operated by a subscriber organization, and (3) for which subscribers receive a bill credit for the electricity generated in proportion to the size of the subscriber's subscription." In this definition, a subscriber organization is the entity that owns and operates the CSG (typically a solar developer), and the subscriber is the individual or organization that subscribes to that CSG facility.

The 2023 legislation "sunset" the original 2013 program (the "Legacy program") and established a Low- and Moderate-Income Accessible CSG program ("LMI-Accessible CSG Program") in Minnesota, effective January 1, 2024. Any Minnesota utility is authorized to establish a CSG program subject to Minnesota Public Utilities Commission (MPUC) review and approval, but Minn. Stat. § 216B.1641 only requires that Xcel Energy (Xcel)—Minnesota's largest investor-owned utility—offer such a program.

Major differences between the Legacy program and the LMI-Accessible CSG Program include annual CSG capacity limits, requirements that CSG facility subscriptions consist of minimum percentages of LMI subscribers and public interest or affordable housing subscribers, and consumer protections for both subscribers and non-subscribers. The new program seeks to expand CSG access to LMI and public interest customers to help those customers reduce their electricity bills while expanding clean energy deployment. The Minnesota Department of Commerce (Department) is responsible for administering the LMI-Accessible CSG Program. For more information on LMI-Accessible CSG Program requirements and how it differs from the Legacy program, refer to Section 2.4, *LMI-Accessible CSG Program Updates and Implementation*.

Pursuant to MN Laws 2023, Ch. 60 (H.F. 2310), Commerce is required to contract with a third party to study the LMI-Accessible CSG Program. Commerce must submit a report to the legislature by December 15, 2024, and include the following:

1. A comparison of the program with similar programs operated in other jurisdictions, including a comparison of program structure, the manner in which applications are submitted and reviewed, how related infrastructure upgrades are prioritized and funded, and how regulations and penalties are structured;
2. An analysis of the cost to ratepayers of operating the community solar garden program and a comparison with the cost to ratepayers of other potential options for encouraging the adoption of solar electricity generation in this state; and
3. An analysis of how the community solar program impacts interconnection and infrastructure upgrade needs and challenges.

This report aims to fulfill these three requirements.

Report Overview and Structure

Consistent with the requirements listed above, Commerce hired the Great Plains Institute (GPI) and its subcontractors, the National Association of State Energy Officials (NASEO), and Synapse Energy Economics, Inc. (Synapse) to prepare this report. This report presents a comprehensive analysis of the LMI-Accessible CSG Program, organized as follows.

First, the report authors provide a review of the LMI-Accessible CSG Program as it is currently implemented and administered. This section includes the following material:

- A high-level overview of community solar in the state and an overview of key legislative context relevant to the LMI-Accessible CSG Program;
- An overview of important regulatory proceedings and decisions since 2013, focusing on context important to the development and implementation of the LMI-Accessible CSG Program;
- A review of existing Department-developed materials (including but not limited to program administration and communications materials);
- A summary of major differences between the LMI-Accessible CSG Program and the Legacy program; and
- Several stakeholders' perspectives on the LMI-Accessible CSG Program, as informed by interviews.

Second, the report contains a cross-jurisdictional analysis that compares Minnesota's LMI-Accessible CSG Program to community solar programs in other jurisdictions with similar goals, including goals related to improving low- and/or moderate-income customers' access to community solar. The cross-jurisdictional analysis considers factors including program structure, approach to application submittal and review, how related infrastructure upgrades are prioritized and funded, and how regulations and penalties are structured. This section aims to provide Commerce with valuable insights regarding other community solar program approaches and implementation that could help further inform Minnesota's approach.

Next, the report includes an assessment of the CSG program cost effectiveness through a BCA. In this section, the report authors applied alternative cost tests within the BCA framework to examine the financial impacts of the CSG program on developers and utility ratepayers, including CSG program subscribers (both LMI- and non-LMI subscribers) and non-subscribers. This section identifies the relative benefits and costs to ratepayers associated with Minnesota's LMI-Accessible CSG Program and includes an analysis of program costs compared to other potential paths to encouraging solar deployment in Minnesota.

Finally, the report contains an interconnection analysis. Interconnection is the process by which DERs connect to the utility-owned distribution grid, which can involve an extensive study process to identify potential infrastructure upgrade needs. This section identifies potential LMI-Accessible CSG Program impacts on DER interconnection in Minnesota, including those related to system upgrade needs and the allocation of those upgrade costs, and includes the following material:

- An overview of DER interconnection practices in Minnesota
- A cross-jurisdictional analysis of DER interconnection practices in Illinois, Massachusetts, and Maryland, with additional states discussed on a case-by-case basis

- Recommendations (interwoven throughout the analysis), informed by the cross-jurisdictional comparison of interconnection practices

Throughout the document, the report authors provide cross-jurisdictional analyses and input from subject matter expert interviews and identify recommendations for consideration by the state.

The key findings and recommendations are intended to help Commerce and other entities with CSG program responsibilities ensure that the LMI-Accessible CSG Program can deliver the benefits intended by the legislative updates. Collectively, this report serves to provide valuable information on the legislative and regulatory history of CSG in Minnesota while offering insights and recommendations to achieve legislative goals informed by extensive analysis.

2.0 Overview of Community Solar in Minnesota

The Minnesota Legislature established the state's CSG program in 2013. The law, codified in Minn. Stat. § 216B.1641, established a model for access to solar energy in which "a community solar garden sells electricity generated from solar energy to subscribers who purchase a given portion of its output. It allows access to solar energy by renters and property owners lacking sufficient capital to install their own solar systems or whose property may be shaded or otherwise unsuitable for a solar installation."[1]

Minnesota's 2013 CSG legislation required Xcel Energy (Xcel) to develop a plan to operate a CSG program in the state, subject to MPUC review and approval. The legislation authorized other utilities to elect to submit plans for such programs.

Solar development in Minnesota has proliferated since 2013, and MPUC has issued numerous orders spanning several proceedings that have CSG program implications. In the 2023 session, the legislature successfully passed substantial revisions to the original 2013 legislation, which Governor Walz then signed into law. This legislation "sunset" what is now referred to as the "Legacy" CSG program and established a new program that aims to improve low-to-moderate income participation in CSGs. Commerce administers this new Low- and Moderate-Income Accessible CSG program ("LMI-Accessible CSG Program").

The legislative and regulatory contexts relevant to the transition from the Legacy program to the LMI-Accessible program, as well as observed perceptions among program stakeholders, are described throughout this section.

2.1 Legislative Context

Legacy CSG Program

The 2013 Minnesota Legislature passed numerous provisions that aimed to support solar energy development in the state, which were signed into law by former Governor Dayton. One such provision—Minn. Stat. § 216B.1641—established Minnesota's CSG program. The new program required the affected utility (Xcel) to purchase power generated by qualified participating solar facilities; such

[1] Bob Eleff, *House Research: 2013 Solar Energy Legislation in Minnesota* (August 2013).

facilities could be owned by the utility or by non-utility parties. In exchange for this purchase, facility subscribers would receive solar production bill credits on their energy bills.[2] This became known as Xcel's Solar*Rewards Community program. Other utilities are not prohibited from establishing CSG programs, but the statute mandated that Xcel offer such a program.

The program was heavily utilized such that until 2022, Minnesota led all other states with the largest CSG deployment (in MWs) in the country.[3] In its *2023 Annual Operations Report*, Xcel noted the Legacy program included approximately 900 MW of installed solar at 490 installed sites across 34,398 subscriptions, with an additional 388 MW in progress at 423 sites. The division of subscriber types and allocated capacity is provided below in Table 1.

Table 1 offers a slight modification from how Xcel reported these subscription numbers in its *2023 Annual Operations Report*. In its report, Xcel refers to the "Small General Service" and "General Service" subscriber categories as "Small Business" and "Commercial and Industrial" subscriptions, respectively. As defined on Xcel's Business Customer Resources webpage, "General Service" rates are for non-residential customers with monthly peak usage above 25 kW and "Small General Service" rates are for residential customers with monthly peak usage under 25 kW. Given this distinction, the "General Service" category listed in Table 1 includes non-residential facilities such as commercial and industrial customers, as well as schools, hospitals, government buildings, and other subscribers with larger electricity demand.

Table 1: Overview of Legacy program subscribers (by customer class) and subscription capacity (data through January 2024)

Subscriber Type	Unique Subscribers†	% of Total Subscribers	% of Total Subscription Capacity
Residential	26,244	89%	16%
Small General Service	1,019	3%	1%
General Service‡	1,710	6%	81%
Other§	425	1%	2%

Source: Xcel Energy's Legacy Solar*Reward Community Program: 2023 Annual Operations Report.

†As documented in Xcel's 2023 Annual Compliance Report, the total number of CSG subscriptions and the total number of CSG subscribers are not necessarily identical. For example, Xcel notes that a single "unique" commercial (or General Service) customer could have multiple accounts and, thus, multiple CSG subscriptions. Xcel's *2023 Annual Compliance Report* documents a total of 29,398 subscribers across a total of 34,398 subscriptions through January 2024.

‡In its compliance report, Xcel explains that "many commercial subscribers, as defined by the Standard Industrial Classification (SIC), include government entities, schools, office buildings, or agriculture-related

[2] Bob Eleff, *House Research: 2013 Solar Energy Legislation in Minnesota* (August 2013).

[3] Minnesota Solar Energy Industries Association, "Minnesota Lawmakers Announce Long-Awaited Community Solar Garden Updates," press release, May 17, 2023, https://www.mnseia.org/minnesota-new-community-solar-policy.

entities." For this reason, the "Commercial & Industrial" subscriber type listed in Table 1 includes customers that would be considered "public interest" entities in the LMI-Accessible CSG Program. In a 2024 Department-conducted analysis of CSG capacity by subscribers by customer rate class, Commerce found that public interest subscribers (public and private schools, hospitals and clinics, and churches) represented over half of program capacity for CSG subscribers under the Applicable Retail Rate (ARR). In the analysis, Commerce also found that public interest and residential subscribers made up 70 percent of subscribed capacity under the ARR.

[§]The "other" category generally consists of other governmental customers, such as municipal pumping and street lighting.

The Legacy program received considerable attention from the legislature in the 2013–2021 period. From 2013-2023, lawmakers, stakeholders, and industry groups worked to amend the program.[4] Stakeholders continued to discuss program elements as stakeholders gained experience through implementation, consumer and utility program costs, subscriber characteristics and rules, project location requirements, project sizes, and other topics. The debates culminated in the 2023 legislation discussed in the following section.

2023 Legislative Considerations for Improving LMI -Accessibility

The 2023 legislative session included significant discussion regarding potential changes to the Legacy CSG program (which, at the time, was the active CSG program). In May 2023, the Minnesota House of Representatives and Senate approved the provisions establishing the updated program, as described in greater detail in Section 2.4, *LMI-Accessible CSG Program Updates and Implementation*. Testimony and deliberations from relevant House and Senate committee hearings leading up to the House and Senate votes are summarized below.

The 2023 legislation—which sunset the Legacy program and established the new LMI-Accessible CSG Program—includes specific carve-outs and requirements that aim to improve program access and participation among potential LMI subscribers. The program specifically defines an LMI subscriber as follows.

> **Minnesota Statutes § 216B.1641, Subd. 2., *Definitions.***
>
> *(c) "Low- to moderate-income subscriber" or "LMI subscriber" means a subscriber that, at the time the community solar garden subscription is executed, is:*
>
> > *(1) a low-income household, as defined under section 216B.2402, subdivision 16;*[5] *or*
> >
> > *(2) a household whose income is 150 percent or less of the area median household income.*

[4] Minnesota Solar Energy Industries Association, "Minnesota Lawmakers Announce Long-Awaited Community Solar Garden Updates," press release, May 17, 2023, https://www.mnseia.org/minnesota-new-community-solar-policy.

[5] Minnesota Statute § 216B.2402 Subd. 16 defines a low-income household as "*a household whose household income: (1) is 80 percent or less of the area median household income for the geographic area in which the low-income household is located, as calculated by the United States Department of Housing and Urban Development; or (2) meets the income eligibility standards, as determined by the commissioner, required for a household to receive financial assistance from a federal, state, municipal, or utility program administered or approved by Commerce.*"

A more detailed summary of the LMI-Accessible CSG Program, including a description of some of the key ways in which it differs from the Legacy program, is provided in Section 2.4, *LMI-Accessible CSG Program Updates and Implementation*. CSGs approved before January 1, 2024, remain subject to Legacy program rules and requirements. Otherwise, projects proposed on or after that date are subject to the LMI-Accessible program rules and requirements.

House Climate and Energy Finance and Policy Committee

The House Climate and Energy Finance and Policy Committee discussed the proposed revisions to the CSG program, as outlined in House File 2432 (HF 2432) at its March 15, 2023, hearing. At the conclusion of the hearing, HF 2432 was laid over for inclusion in the Omnibus appropriations bill for environment, natural resources, climate, and energy finance and policy (House File 2310, or HF 2310). Discussions pertaining to HF 2432 starting at approximately the 55-minute mark in this hearing recording.

The Committee Chair introduced the bill to the committee, noting that Minnesota's then-current (now-Legacy) program was "a successful subscriber-based community solar program where residential, commercial, and public entities can purchase subscriptions to offset their energy use." The Committee Chair emphasized that CSGs are not intended to replace other models of solar, but rather fill a gap that is not addressed by either utility-scale solar or non-CSG small rooftop installations, noting that the proposed revisions would expand program access, especially for low-income individuals.

Multiple groups offered testimony at the hearing:

- Individual CSG subscribers
- Solar developers
- Solar industry associations
- Xcel

Individual CSG subscribers shared that having the option to subscribe to a CSG facility was beneficial, especially for residents who would not have otherwise been able to deploy solar energy on-site at their own home. Subscribers expressed support for expanding program access to make it easier for renters, low-income residents, and people of color to participate in a program that both reduced their electricity bills and helped them more directly work toward addressing the climate crisis. Some subscribers suggested value in offering a higher bill credit to low-income residents and preventing developers from requiring credit checks. Additionally, one subscriber expressed general support for raising the 1 MW cap to a 5 MW cap. This subscriber noted that because the cost to install community solar is slightly higher than the cost to install utility-scale solar, this increase in facility size improves installation efficiency by enabling economies of scale that lower facility cost. In summary, subscribers viewed CSGs as a tool that enabled households to play a larger role in addressing climate change and that helped grant them a path toward energy independence.

Community solar developers and solar industry association representatives shared that Minnesota's CSG program is often viewed as one of the most successful programs nationwide, but also identified areas where the CSG program could potentially be improved. These testifiers spoke to CSG as an opportunity for low-income households to reduce their bills and supported program revisions that would help improve program access for that demographic. They also spoke to how an increased facility size cap brings efficiency benefits, which would help reduce barriers to program entry and participation, and they encouraged the removal of the contiguous county provision, which has been done in other jurisdictions.[6]

Community solar developers and industry representatives also spoke to cost and rate considerations. Specifically, they testified that arguments that the CSG program contributed to higher ratepayer costs use data from early program years, during which ratepayer costs were based on the Applicable Retail Rate (ARR) methodology, which is the methodology applicable to 80 percent of Minnesota's CSG facilities. By switching to Commerce's Value of Solar (VOS) methodology in later program years, these costs were significantly reduced (approximately 50 percent lower). For further details on regulatory conversations pertaining to ARR and VOS, refer to the overview of Docket No. E002/M-13-867: *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program* in Section 2.2, *Program Context*.

As the only utility obligated to offer a CSG program, representatives from Xcel also testified, acknowledging that DERs play an important role in the company's energy system. However, the company stated that program outcomes had eventually exceeded the bounds of what was originally intended for the Legacy program. Xcel additionally expressed cost concerns related to CSGs, stating that even at the VOS rate, CSGs are more expensive than the cost of solar that Xcel could otherwise procure on the market. Additionally, Xcel stated that most costs related to CSGs go directly to the developer or facility owner, not to subscribers. Finally, Xcel expressed concerns about grid congestion, noting that in some places in Minnesota, even small rooftop systems are no longer practical due to the high number of CSG facilities also interconnected in those regions.

Following these testimonies, committee members asked questions about the CSG program and the proposed program changes. At times, committee members asked questions from individuals who had provided testimony to enable them to better understand the program. Questions and discussions from committee members are summarized below. For a complete record of the hearing and the exact language from representatives' questions and responses provided, please refer directly to the hearing.

Overall, committee members expressed some concerns related to the potential for cost-shifting, stating that while individual CSG subscribers' bills may be lower, the overall costs (on a portfolio level) were higher than they would be under more widespread utility-scale solar. Committee members asked questions pertaining to the amount of Xcel's load served by CSG facilities, as well as the cost of those facilities. Committee members heard that while CSGs account for 3.5–5 percent of Xcel's retail load, they account for more than 15 percent of Xcel's fuel cost. However, testifiers clarified that this is a complex comparison, stating that under the CSG model, 100 percent of costs are passed through to the fuel clause, but with utility-scale installations, many costs are separately passed through to ratepayers via separate fees and bill line items.

Committee members also sought information on how Minnesota's program and potential CSG deployment in Minnesota compares to other jurisdictions. Committee members sought to better

[6] The "contiguous county requirement" under the legacy program is described in § 216B.1641 Subd. 1(c) required that "the solar generation facility must be located in the service territory of the public utility filing the plan. Subscribers must be retail customers of the public utility located in the same county or a county contiguous to where the facility is located."

understand the potential extent of CSG capacity under the revised programs. Testifiers noted that it is difficult to fully predict exactly how much solar would be deployed through the CSG program moving forward, but in general, considered it unlikely that Minnesota would reach the level of CSG deployment sought in New York, which has aggressive DER targets (10 GW) under the Climate Leadership and Community Protection Act of 2019.

Additional questions pertained more specifically to program implementation. One committee member asked whether the bill had provisions to incentivize CSG development in the Twin Cities Metro Area to minimize potential impacts on agricultural land in Greater Minnesota. The proposed program changes do include strategies to increase Metro Area CSG development, and the Committee Chair clarified that no aspect of the revised CSG program would include eminent domain; any CSGs would be private developments. Further questions related to program implementation included a discussion regarding program caps and how such a cap may or may not be established.

Several committee members supported keeping the "contiguous county" requirement, which had been struck from the bill. According to one such committee member, farmers can receive significantly more money per acre by leasing their land to a solar developer ($1000–1,500/acre) compared to the $200–300/acre they would receive by leasing their land to another farmer. This committee member stated that this has contributed to a shift from agricultural land uses to solar land uses in parts of Greater Minnesota. However, a motion to reinstate the contiguous county language did not pass.

A committee member also asked a representative from a community solar industry association to share their experience working with other states to help better understand how Minnesota's CSG program compares to similar programs in other jurisdictions. The testifier shared that many states look to Minnesota as an example in this area. They shared that the Arizona Corporation Commission requested that their staff model their own CSG program after Minnesota's. The testifier also noted pending legislation in both Montana and Alaska that was substantially similar to Minnesota's legislation. This individual also shared that they commonly receive questions from entities seeking to learn from and model Minnesota's CSG approach (as well as approaches in Colorado and New York).

Senate Committee on Energy, Utilities, Environment, and Climate

The Minnesota Senate Committee on Energy, Utilities, Environment, and Climate discussed Senate File 2688 (SF 2688), which contained the proposed revisions to the CSG program, during its March 22, 2023, hearing. A recording of the hearing is available on the Minnesota Senate Media Services YouTube channel, with discussions pertaining to SF 2688 starting at approximately the 1-hour, 37-minute mark.

The Committee Chair introduced the bill to the committee, noting that Minnesota's then-active (now-Legacy) program aims to enable deployment of distributed solar energy statewide in which individuals can choose to subscribe to that renewable energy in a cost-competitive way. The Committee Chair described some highlights of the proposed bill revisions, which aim to further improve upon the program's success:

- Removal of contiguous county requirement
- Annual cap on new community solar
- Establishes a list of approved non-residential subscribers

- Establishes required LMI residential subscriber thresholds for CSGs

Multiple groups offered testimony at the hearing:

- Xcel
- Solar industry associations
- Clean energy organizations
- Solar developers
- Labor unions
- Consumer advocacy group
- An individual CSG subscriber

Overall, the parties' testimony in the SF 2688 hearing was similar to the testimony provided in the HF 2432 hearing. Notably, Xcel shared that SF 2688 (as amended since the HF 2432 hearing) addressed many of its concerns. In particular, Xcel emphasized its support of the targeted LMI aspect of the program. The solar industry associations' testimony was similar to the testimony they provided to the House Climate and Energy Finance and Policy Committee. However, at the Senate Committee on Energy, Utilities, Environment, and Climate hearing, the solar industry associations expressed additional concern for the proposal to eliminate what would become the Legacy program if the bill were to pass, given that program's successful history of deploying CSGs. Solar developers expressed similar concerns.

Labor organizations also testified in favor of SF 2688, stating that the bill would introduce competition into the market. Labor was also supportive of the introduction of a prevailing wage requirement, which was absent from the original CSG program. However, in their testimony, labor organizations suggested that instead of continuing to utilize a subscription model, all benefits should be made equally available to all customers, and all costs should be shared equally across all customers.

An advocacy organization for utility customers also provided testimony, acknowledging that Minnesota's CSG program had successfully enabled widespread CSG deployment, but stated that addressing cost concerns—including concerns about costs that would be passed onto ratepayers—remains important. Specifically, this organization noted that residential subscribers represent only a small percentage of CSG program subscribers and that low-income subscribers represent less than 1 percent of total subscribers. For this reason, this organization was supportive of consumer protection improvements to ensure that CSGs remained beneficial to residential subscribers and non-subscribers alike. Similarly, this organization supported the move to increase program competitiveness through a request for proposals (RFP) process, which they suggested would drive down costs. The advocacy organization stated that they would support mechanisms that would enable federal savings and incentives to be passed down to ratepayers.

In the SF 2688 hearing, clean energy organizations also testified, expressing general support for any program updates that would support continued solar deployment in Minnesota. Clean energy organizations emphasized the importance of continued work with stakeholders to improve equity outcomes while addressing issues related to program costs and distribution system impacts.

Committee members asked questions about the CSG program, the proposed changes to it, and the testimonies provided. A summary of questions from representatives and the responses provided is included below. For a complete record of the hearing and the exact language from representatives' questions and responses provided, please refer directly to the hearing.

Committee members asked several clarifying questions about SF 2688. One member sought clarification on the definition of a subscriber and asked if either becoming a CSG subscriber or terminating a CSG would involve fees. The committee member was informed that the intent would be to keep any such fees as minimal as possible. Another committee member sought clarity on whether protections were in place to ensure that at the end of a CSG facility's operational life, ratepayers and residents would not be burdened by decommissioning and cleanup costs if the CSG developer was no longer in business. The Committee Chair informed this committee member that these costs are built into overall facility costs and are thus accounted for.

In further discussion about SF 2688, one committee member acknowledged that the bill seeks to address some issues associated with the 2013 program, including issues related to program costs and facility ownership outside of Minnesota, but remained unsupportive of CSGs in general. Another committee member felt that the CSG program had reached outside of its original intended scope, which they described as a solar subscription option to residential households where rooftop solar was infeasible. This committee member appreciated the requirement that at least 25 percent of CSG capacity be subscribed to by residential subscribers and advocated that this number be raised to at least 50 percent. A representative from a solar developer who had provided testimony earlier stated that while the original program was intended to be accessible to residential subscribers, it was not a residential-only program.

2.2 Program Context

Program Administration and Oversight

LMI-Accessible CSG Program Administration and Oversight (January 1, 2024–present)

The 2023 legislation established Commerce as the administrator for the LMI-Accessible CSG Program for new facilities proposed after January 1, 2024. MPUC continues to be responsible for program tariff oversight, review, and approval. Since January 1, 2024, Commerce has established and deployed a competitive application process for CSG facility approval under the LMI-Accessible CSG Program. Reviewing these applications has been Commerce's primary program-related activity this year.

So far, Commerce has issued solicitations in monthly "batches," the first of which started on February 1, 2024, on its RFP web page (Commerce posted draft information about the first batch on January 2, 2024). The application window for each batch of applications begins on the first of each month and remains open for 21 days.

Commerce reviews project applications for completeness, including verification of the application components required under Minn. Stat. § 216B.1641, Subd. 5, and the project eligibility requirements identified in Subd. 6, 7c, and 10b. These eligibility requirements are summarized in Section 2.4, *LMI-Accessible CSG Program Updates and Implementation*, which provides an overview of differences between the Legacy and LMI-Accessible programs.

As of September 2024, Commerce has approved 62 projects from nine distinct developers totaling 61.7 MW of CSG capacity through Batches 1–8, with an additional 2.0 MW under review for Batch 9 as of early November, 2024.[7] Commerce provides a schedule for the remaining 2024 batch application periods posted on the CSG program website.

Legacy Program Administration and Oversight (2013–December 31, 2023)

MPUC oversaw Xcel's implementation of the Legacy program, including program tariff approval. The 2013 legislation required that the utility purchase CSG-generated power at a rate calculated under Minnesota Statute § 216B.164, Subd. 10. Minnesota Statute § 216B.164, Subd. 10 enables utilities to request MPUC approval for an alternative tariff that provides compensation for solar-specific resource value via a bill credit mechanism. If a utility did not seek MPUC approval for an alternative tariff, the ARR would instead apply.

Minnesota Statute § 216B.164, Subd. 10 establishes that the compensation calculation for the alternative tariff must include consideration for values that solar resources provide to the utility, to utility customers, and to society more broadly. The legislation directed Commerce to develop a methodology for calculating this value, referred to as the "Value of Solar" (VOS). VOS is a calculation that considers the multiple energy and non-energy values of distributed solar resources.

In April 2014, Commerce finalized the VOS methodology for use by participating utilities, and Xcel filed alternative tariffs in accordance with this methodology. In 2023, MPUC issued an Order "[discontinuing] the value-of-solar filing requirement" for non-Legacy CSGs.[8] The regulatory record documenting these shifts in approach is summarized throughout this section.

Relevant Regulatory Proceedings

This section provides high-level summaries of eight key MPUC proceedings with implications for CSGs in Minnesota since the Legacy program's inception in 2013, as outlined below in Table 2. The summaries aim to provide only a brief overview of those proceedings, focusing on information that is relevant to the current CSG program development and status.

[7] As of early November 2024, less than two-thirds of the allocated capacity for 2024 has been approved. Minnesota may not be able to reach its 100 MW goal for Year 1 since program eligibility requires an interconnection agreement in hand, and it takes 9-12 months to reach an interconnection agreement, especially for those projects applying for interconnection in constrained areas.

[8] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Discontinuing Value-of-Solar Filing Requirement (February 23, 2024).

Table 2: List of MPUC proceedings with CSG and/or interconnection implications

Docket No.	Proceeding Title
E002/M-13-867	*In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*
E002/CI-23-335	*In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*
E-999/M-14-65	*In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, Subd. 10 (e) and (f)*
E002/M-21-695	*In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*
E999/CO-16-521	*In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*
E002/M-23-452	*In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*
E002,E015,E017/CI-24-288	*In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*
E002,E015,E017/CI-24-318	*In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy*

For more detail on these proceedings, including a summary of key orders and other major filings as well as links to referenced filings, please refer to Appendix A, *Summary of Key Regulatory Proceedings*.

Docket No. E002/M13-867: In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program

As required under Minn. Stat. § 216B.1641 (as passed in 2013), Xcel submitted its Petition for Approval of its first proposed CSG plan and tariff on September 30, 2013.[9] After an extensive public review and comment period, MPUC rejected Xcel's initial CSG plan and tariff filing on April 7, 2014, directing Xcel to file a revised proposal either (1) utilizing Commerce-developed VOS tariff recently approved by MPUC, or (2) providing calculations demonstrating why the VOS rate should not be used.[10]

[9] Xcel Energy, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Petition: Community Solar Gardens Program (September 30, 2013).

[10] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Rejecting Xcel's Solar Garden Tariff Filing and Requiring the Company to File a Revised Solar-Garden Plan (April 7, 2014).

In May 2014, Xcel submitted a revised proposal in which it argued that VOS was not in the public interest. In September of that year, MPUC issued an Order approving Xcel's filing (with modification), concurring that VOS was not in the public interest at the time and directing Xcel to continue using the ARR for CSG subscribers. However, MPUC also directed Xcel to continue filing annual VOS inflation updates and updated rate calculations.[11]

Conversations regarding whether MPUC should formally adopt VOS over ARR continued in 2015–2016. On September 6, 2016, MPUC issued an Order approving VOS for use as a bill credit rate for all CSG applications starting in 2017, directing Xcel to modify its tariff accordingly. In this Order, MPUC also directed Commerce to analyze whether the existing VOS methodology should be adjusted with a positive or negative cost adder for locational factors (e.g., whether the CSG facility was sited on brownfields, on prime agricultural land, etc.) and/or subscriber type (residential subscribers and low-income residential subscribers). In March 2017, Commerce submitted a report to MPUC in response to this directive, recommending that MPUC adopt positive/negative cost adders for facilities meeting certain locational criteria and that MPUC consider low-income residential cost adders once Xcel had developed a dedicated low-income CSG proposal.

In February 2018, Xcel filed an analysis of residential CSG subscribers, including an analysis of how a dedicated residential carve-out could be implemented in response to Commerce's report. On November 16, 2018, MPUC issued an Order adopting a 1.5-cent per kWh residential cost adder to the VOS bill credit rate.

In spring 2023, the legislature passed the CSG program updates described throughout this report, to be implemented starting January 1, 2024. In response to this, MPUC issued a Notice of Comment Period on July 26, 2023, in this docket and also in a new proceeding (Docket No. E002/CI-23-335, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*). Through opening the new proceeding, MPUC directed conversations related to new program implementation to that docket. Docket No. E002/CI-23-335 is summarized below.

Conversations related to VOS continued in Docket No. E002/M-13-867, in alignment with Xcel's annual compliance filing and tariff update obligations. In fall 2023, MPUC sought comments on the role of VOS moving forward, given the substantial program changes. Specifically, MPUC asked parties to share perspectives on whether they should discontinue Xcel's VOS requirement and asked if there were other potential uses and applications for the VOS.

Following the public comment period on this matter, MPUC issued an Order discontinuing Xcel's VOS requirement on February 23, 2024, stating that "the actual uses for the VOS remain unclear, and requiring annual updates necessitates additional proceedings that expend valuable stakeholder and Commission time. The Commission concludes that the need to preserve scarce regulatory resources outweighs the possible future usefulness of VOS annual filings."[12] In this Order, MPUC established that

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[11] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Approving Solar Garden Plan with Modifications (September 17, 2014).

[12] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Discontinuing Value-of-Solar Filing Requirement (February 23, 2024).

Legacy CSG facilities (i.e., facilities approved before January 1, 2024) will continue to utilize the VOS bill credit, but that new CSG facilities subject to the LMI-Accessible CSG Program would instead be subject to new program parameters.

On May 30, 2024, MPUC issued two orders in this proceeding:

- *Order implementing new legislation governing community solar gardens*, and
- *Order approving community solar garden program rate-transition proposal with modifications*

In the first of these two orders (which was cross-filed in Docket No. E002/CI-23-335), MPUC provided clarification regarding CSG program implementation considerations including Xcel's use of their online portal for applications, as described in greater detail under the Docket No. E002/CI-23-335 summary. In the second order, MPUC approved Xcel's September 25, 2023, compliance filing (as modified),[13] which proposed to switch CSG subscriptions that fall under the ARR credit to the VOS rate.

In June 2024, multiple parties filed petitions for reconsideration of MPUC's second May 30 Order, including a request for rehearing filed jointly by several solar developers and developer associations. These petitions largely focused on the appropriateness of transitioning from the VOS tariff to the ARR for CSG subscriptions, requesting that MPUC reject Xcel's proposal to switch these subscriptions from the ARR credit to the VOS rate.[14]

On August 1, 2024, MPUC held a meeting in response to the petitioners' requests for reconsideration and a rehearing. At this meeting—and as described in the subsequent Order issued on August 16, 2024—MPUC denied the petitioners' requests for a rehearing.[15] In August and September 2024, these same joint petitioners and others filed additional Applications for Rehearing in response to MPUC's August 16 Order, seeking to ensure that parties preserved their ability to challenge the May 30 Order in question on appeal.[16] On October 10, 2024, MPUC held a hearing to discuss whether to reconsider its August 16 Order denying the petitions, grant reconsideration of the August 16 Order, and/or stay implementation of this May 30 Order. At the hearing, MPUC declined the request to reconsider its August 16 decisions.

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13 Xcel Energy, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Proposal for Switching ARR-era Community Solar Gardens to Appropriate VOS Rate (September 25, 2023).

14 CCSA, MnSEIA, Cooperative Energy Futures, PureSky Community Solar, Inc., SunShare, LLC, BHE Renewables, and Cypress Creek Renewables, LLC. *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its* Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Joint Application for Rehearing (June 20, 2024).

15 Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Denying Requests for Reconsideration of May 30, 2024 (August 16, 2024).

16 CCSA, MnSEIA, Cooperative Energy Futures, PureSky Community Solar, Inc., SunShare, LLC, BHE Renewables, and Cypress Creek Renewables, LLC. *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Joint Application for Rehearing (September 5, 2024).

Docket No. E002/CI-23-335: In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program

As discussed above, MPUC opened this new proceeding on July 26, 2023, in response to the updated CSG legislation passed in spring of that year. Through this proceeding, MPUC sought public feedback and comments on questions and topics pertaining to the transition from the Legacy program, compensation under the new program, and billing requirements. Following public comment periods, MPUC issued an order implementing the new CSG legislation on December 28, 2023.[17]

MPUC's December Order established that CSG projects with applications deemed complete prior to January 1, 2024, fell under the Legacy program (but CSG projects with applications deemed complete after that date would be subject to the new LMI-Accessible CSG Program requirements). In this Order, MPUC also established means to implement requirements pertaining to consolidated billing, application fees, participation fees, non-subscriber protections, and renewable energy credit ownership. The Order also established annual tariff update compliance filing requirements for Xcel. For exact language and details pertaining to each of these implementation requirements, please refer directly to the Order.

Xcel submitted its first annual tariff filing under the LMI-Accessible CSG Program on January 5, 2024, which received objections from several parties who felt that Xcel's proposed application fee collection method and timeline violated the State of Minnesota Distributed Energy Resources Interconnection Process (MN DIP). In response to these concerns, MPUC issued an Order on May 30, 2024 (also described under Docket No. E002/M-13-867 summary), stating that "for non-legacy CSGs, Xcel must use its Distributed Generation portal for interconnection applications. Xcel may use or modify its existing CSG-specific portal once projects are allocated capacity in the program by Commerce."[18] The Order also authorized Xcel to use or modify its existing CSG application portal once Commerce granted capacity for proposed CSG projects. Additionally, the Order established that Xcel may only collect application fees once a project has been approved by Commerce to participate.

Discussions related to LMI-Accessible CSG Program implementation continue in Docket No. E002/CI-23-335.

Docket No. E999/M-14-65: In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, Subd. 10 (e) and (f)

As described in the summary of Docket No. E002/M-13-867, Commerce submitted a proposed VOS Methodology for MPUC review, as required under Subd. 1(d) of Minnesota Statute §216B.164. MPUC approved Commerce's methodology (with modifications) on April 1, 2024. From this point forward, Xcel submitted annual VOS calculations and compliance filings in Docket No. E002/M-13-867, though ARR remained the effective CSG bill credit methodology until September 2016.

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[17] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335. Order Implementing New Legislation Governing Community Solar Gardens (December 28, 2023).

[18] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Order Implementing New Legislation Governing Community Solar Gardens (May 30, 2024).

Xcel proposed modifications to the VOS methodology on August 1, 2019, arguing that over time, the VOS methodology had resulted in rates that are "unreasonable, unrepresentative, and [that] clearly [fall] outside of the public interest."[19] MPUC issued an order in December of that year expressing general agreement with aspects of Xcel's argument and approving modifications to the methodology.

With the updated CSG legislation, MPUC found a need to clarify the role, if any, of VOS under the new LMI-Accessible CSG Program, which has different bill credit compensation specifications than the Legacy program. MPUC directed filings and deliberations related to the future use of VOS under the new program to the general CSG proceeding and the proceeding focused on implementing the new program (Dockets No. E002/M-13-867 and E002/CI-23-335, respectively). As indicated above, in February 2014 MPUC issued an order discontinuing the VOS requirement.

Docket No. E002/M21-695: In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility

On September 23, 2021, Xcel filed a joint proposal with Energy CENTS Coalition, Mid-Minnesota Legal Aid, and the Citizens Utility Board of Minnesota in Docket No. E002/M-13-867. These comments were cross-filed in Docket No. E002/M-21-695, opening this new proceeding. The proposal aimed to address consumer protection concerns related to the CSG program.

In their comments, the joint parties state that with the proposed modifications, "more tenants will retain essential regulatory consumer protections provided by the Cold Weather Rule, protection from disconnection of service, and maintain the ability to qualify for the maximum LIHEAP [Low-Income Home Energy Assistance Program] benefit and supplemental utility affordability programs." Additionally, the proposal aimed to address situations in which "tenants of multi-unit buildings [had] their accounts transferred to the building owner/landlord's name, altering the customer of record so that the building owner can subscribe to a CSG and receive the associated CSG bill credits."[20]

On June 24, 2022, MPUC did not approve the joint filers' proposal but did direct Xcel to modify its tariffs and convene a stakeholder process in an effort to mitigate identified issues. The Order also established internal directives within MPUC, which will further develop the regulatory record regarding identified consumer protection issues. Xcel submitted a revised tariff filing in response to MPUC's Order, which MPUC approved in August 2023 (at which point in time the LMI-Accessible CSG legislation had passed). Xcel also filed the results of its stakeholder engagement process in January 2024, which Commerce recommended that MPUC approve. Additional parties also provided feedback and suggested modifications to Xcel's proposed In Care of Billing proposal and Xcel's current opt-in/opt-out tariff provisions.

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[19] Xcel Energy, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f), Docket No. E-999/M-14-65, Petition – Value of Solar Methodology (August 2, 2019).

[20] Xcel Energy, *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*, Docket No. E002/M-21-695, Joint Petition and Proposed Tariff Modifications (September 23, 2021).

On August 27, 2024, MPUC issued a Notice of Supplemental Comment Period seeking further input from interested parties on potential actions in response to the identified issues. In their comments, Commerce noted that an opt-in/opt-out model offers improved control for tenants but also presented a situation in which tenants would need to choose between eligibility for energy assistance programs and participation in such programs. Commerce encouraged Xcel to further explore possible solutions to identified issues.[21] Other parties also emphasized the need for MPUC to continue to work toward solutions. Xcel's response comments and parties' reply comments are due by late October and early November 2024, respectively.

Docket No. E999/CO-16-521: In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611

On June 21, 2016, MPUC opened Docket No. E999/CO-16-521 to explore and update the 2004 Minnesota Standards for Interconnection of Distributed Generation. The 2004 standards were developed in accordance with Minn. Stat. §216B.1611, which directed MPUC to initiate a proceeding to develop generic interconnection standards for distributed generation.

In response to early feedback and comments in Docket No. E999/CO-16-521, MPUC established a workgroup focused on updating and improving the state's distributed resource interconnection standards and to update the Minnesota standards in accordance with the Federal Energy Regulatory Commission's recent Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA). Following the extensive working group effort, MPUC issued an Order adopting an updated interconnection process and an updated standard interconnection agreement on August 13, 2018.[22] These became known as the State of Minnesota Distributed Energy Resources Interconnection Process (MN DIP) and Distributed Energy Resource Interconnection Agreement (MN DIA), respectively. The MN DIP and MN DIA underwent several minor adjustments before formal adoption by MPUC on April 19, 2019.[23] For additional details regarding MN DIP and MN DIA, please refer to Section 5.1, *DER Interconnection in Minnesota*.

In January 2017, MPUC directed the workgroup to discuss updates to technical interconnection requirements to ensure consistency with recently revised IEEE standards (IEEE 1547-2018).[24] MPUC approved updates to the technical interconnection requirements (the Minnesota DG Technical

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[21] Minnesota Department of Commerce, *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*, Docket No. E-002/M-21-695, Comments of the Minnesota Department of Commerce, Division of Energy Resources (October 2, 2024).

[22] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018).

[23] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, Docket No. E-999/CI-16-521, Order Approving Tariffs with Modifications and Requiring Compliance Filings (April 19, 2019).

[24] IEEE, or the Institute of Electrical and Electronics Engineers, maintains a series of technical standards for electronics and electric systems. This includes the Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (more commonly referred to as IEEE 1547-2018).

Interconnection and Interoperability Requirements, or "TIIR") on January 22, 2020.[25] At that time, the TIIR was under partial implementation. Following additional workgroup discussion regarding the market readiness of advanced inverter technology, MPUC issued an additional order on October 6, 2023, authorizing immediate full implementation of the TIIR and mandating full implementation by January 1, 2024.[26]

Docket No. E999/CO-16-521 continues to be a venue for conversations regarding Minnesota's interconnection standards and any potential revisions or updates that may be necessary to MN DIP and MN DIA. In September 2023, MPUC issued a Notice for Comment seeking feedback on what changes to MN DIP should be considered to meet a new legislative requirement that small (up to 40 kW) customer-sited distributed generation (DG) projects be able to interconnect according to MN DIP procedures, with queue priority granted to these smaller projects. In response to feedback received on this matter, MPUC issued an order on April 14, 2024, requiring that Xcel establish two administrative interconnection queues (a MN DIP variance), with one queue based on geographic considerations (e.g., feeder, substation) and the other being the priority queue for these small (up to 40 kW) project applications. The April Order also directed the workgroup to discuss whether battery storage systems should be evaluated under MN DIP.[27]

Docket No. E-002/M-23-452: In the Matter of Xcel Energy's 2023 Integrated Distribution Plan

Each of Minnesota's rate-regulated utilities must file an "integrated distribution system plan" (IDP) with MPUC every other year. These plans must include data related to the utility's distribution system, including data related to DERs, long-term distribution system planning, the use of non-wires alternatives, and financial data.

Xcel filed its 2023 IDP on November 1, 2023, in Docket No. E-002/M-23-452: In the Matter of Xcel Energy's 2023 Integrated Distribution Plan. MPUC issued a comment period on Xcel's filing and held a hearing to discuss the IDP on July 2, 2024. On September 16, 2024, MPUC issued *Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements*.[28]

In approving Xcel's 2023 IDP, MPUC also included several orders directing workgroups to discuss several topics related to DG and interconnection, with the goal of identifying feasible paths forward related to a number of issues to be included in Xcel's upcoming 2025 IDP filing. Upcoming workgroups and

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[25] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Order Establishing Updated Technical Interconnection and Interoperability Requirements (January 22, 2020).

[26] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Notice of "Readily Available" Advanced Inverters and Full Implementation of Technical Interconnection and Interoperability Requirements (October 6, 2023).

[27] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, E-999/CI-16-521, Order Establishing a Two-Queue System, Directing Further Discussions, and Addressing Miscellaneous Matters (April 15, 2024).

[28] Minnesota Public Utilities Commission, *In the matter of Xcel Energy's 2023 Integrated Distribution Plan,* Docket No. E-002/M-23-452, Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024).

stakeholder processes—as described in MPUC's September 16, 2024, Order and its subsequent Notice of Workgroup Processes and Soliciting Stakeholders[29]—are summarized below in Table 3.

[29] Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, Notice of Workgroup Processes and Soliciting Stakeholders (September 27, 2024).

Table 3: List of upcoming workgroup processes as directed by MPUC's Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements

Workgroup	Workgroup/Stakeholder Process Directive	Schedule Information (subject to change)
DER Cost Sharing Workgroup/Reactive Cost Sharing Workgroup	In a September 26, 2024 Notice, MPUC stated that this workgroup is tasked with "developing the record more fully in this docket" as MPUC works to fulfill the proceeding directives under Minnesota Session Laws (2024), Chapter 126, Article 6, Section 5. Section 5 directs MPUC to "initiate a proceeding to establish by order generic standards for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities at the congested or constrained location and to advance the achievement of the state's renewable and carbon-free energy goals." The workgroup will develop the regulatory record on this topic in Docket E002,E015,E017/CI-24-288, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*. The DER Cost Sharing Workgroup (sometimes referred to as the "Reactive Cost Sharing Workgroup") is summarized in greater detail below under Docket No. E002/CI-24-288.	Group scheduled to meet for the first time in November 2024
Proactive Grid Upgrade Workgroup	In accordance with Order Point 14 in MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements* and as stated in MPUC's Notice Soliciting Stakeholder Members, the Proactive Grid Upgrade Workgroup is tasked with "develop[ing] a framework for proactive upgrades and cost allocation for Commission consideration and possible adoption." The workgroup will develop the regulatory record on this topic in Docket No. E002/CI-24-318, *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy*. The Proactive Grid Upgrade Workgroup is summarized in greater detail below under Docket No. E002/CI-24-318.	• Group scheduled to meet for the first time in November 2024. • Commission goal to complete stakeholder process by July 2025.
Distribution Data Reporting Requirements	MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirement*s "delegate[d] authority to the Executive Secretary to work with Xcel and stakeholders to develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets… to identify which, if any, pieces of information are missing and should be included in future IDPs." In Order Point 13, MPUC specifically directs that the proposal should include reliability data, distribution spending data by IDP budget categories, data pertaining to hosting capacity for generation or load, demographic data (race and income), installed DERs, and specific program enrollment information. MPUC also directed that data be provided at the feeder and/or census block level. This will be part of the IDP Improvements Workgroup.	• Workgroup will start meeting to discuss these topics in 2025. • Data should be incorporated into Xcel's November 1, 2025, IDP filing.
Distributed Generation Working Group (including the Flexible	The Distributed Generation Working Group (DGWG)—established under Docket No. 16-521—has met on an ongoing basis since 2017 to discuss and resolve issues related to DG and interconnection in Minnesota. Order 21 in MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirement*s in Docket No. E-002/M-23-452 states the following: "The	• DGWG is ongoing, continues to meet to address and discuss issues

Workgroup	Workgroup/Stakeholder Process Directive	Schedule Information (subject to change)
Interconnection Working Group)	Commission directs the Distributed Generation Workgroup to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS."	on schedules as identified by MPUC. • Flexible Interconnection Working Group members to attend November DGWG meeting, where priorities related to flexible interconnection will be discussed.
Cost-Benefit Analysis, DERMs, and Planned Net Load	MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirement*s directs Xcel to conduct stakeholder outreach on a number of items related to its distribution system, outlined in several order points. Order Points 10–12 direct Xcel to "engage in additional stakeholder discussions on approaches to apply cost-benefit analyses… strategically to program-level investments for discretionary projects for certification or cost recovery proceedings," and "explain how it would define 'discretionary' spending in this context." Similarly, Order Point 17 directs Xcel to "work with stakeholders to refine its planned net load methodology [and] evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity." Finally, Order Point 22 directs Xcel to conduct stakeholder outreach directly with DER owners/operators to inform such stakeholders about numerous factors related to DERMS including costs/benefits, alternatives to DERMS, and the purpose of using DERMS (i.e., the problems that DERMS aims to address). In its 2025 IDP filing, Xcel must discuss the results of these conversations.	TBD—Engagement processes to be led by Xcel, schedule not yet determined.
IDP Budget Category Amendments	Order Point 7 in MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirement*s directs MPUC's Executive Secretary "to work with Xcel and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data."	Fall 2024–Early 2025
IDP Filing Requirements for Electrification	Order Point 8 in MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirement*s directs MPUC's Executive Secretary "to work with Xcel, Commerce, and stakeholders to modify the IDP reporting requirements to include discussions of the impacts of electrification where appropriate and consider alternative dockets and the timeliness for a beneficial electrification plan and whether the filing requirements should be part of future IDPs."	Fall 2024–Early 2025
Electrification Plan for Xcel Energy	In addition to the "IDP Filing Requirements for Electrification" workgroup described above, MPUC's *Order accepting 2023 Integrated Distribution Plan and Modifying*	TBD—timeline to be established

Workgroup	Workgroup/Stakeholder Process Directive	Schedule Information (subject to change)
	*Reporting Requirement*s directs the Executive Secretary to consider whether Xcel should be required to file a beneficial electrification plan.	upon conclusion of the "IDP Filing Requirements for Electrification" process.

The above list of active or soon-to-start workgroups indicates that issues related to DG in Minnesota—including DG interconnection—are topics of interest across several MPUC proceedings. In directing the formation of these workgroups, MPUC has demonstrated an interest to develop the regulatory record on challenges, issues, and potential solutions related to these topics.

Docket No.E002/CI-24-288: In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas

Minnesota Session Laws (2024), Chapter 126, Article 6, Section 53 directed MPUC to "initiate a proceeding to establish by order generic standards for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities at the congested or constrained location and to advance the achievement of the state's renewable and carbon-free energy goals." On August 30, 2024, MPUC opened a new docket (Docket No. E002, E015, E017/CI-24-288) in accordance with this requirement.

On September 26, 2024, MPUC issued a Notice Soliciting Stakeholder Members in this proceeding. In this notice, MPUC established a DER Cost Sharing Workgroup (also sometimes referred to as the "Reactive Cost Sharing Workgroup"), which it "tasked with developing the record more fully in this docket before [cost sharing] proposals go before the Commission for decision."[30] The proceeding will occur across three phases, as summarized below.

- Phase 1: The DER Cost Sharing Workgroup will meet jointly with the Proactive Grid Upgrade Workgroup (described in greater detail below under Docket No. E002, E015, E017/CI-24-318). During this phase, the two workgroups will discuss differences in scope and timelines between the DER Cost Sharing Workgroup and the Proactive Grid Upgrade Workgroup, as well as areas of topical overlap.
- Phase 2: Meetings held during this phase will enable open communication among DER Cost Sharing Workgroup as the group discusses technical requirements outlined in Minnesota Session Laws (2024), Chapter 126, Article 6, Section 53 including expanding hosting capacity, reducing the cost burden on individual projects that may trigger upgrade needs, and more.
- Phase 3: This phase will include a formal comment period in the proceeding, with the goal of developing the written record on issues and solutions. Phase 3 will be informed by prior phases in the proceeding.

The DER Cost Sharing Workgroup (or Reactive Cost Sharing Workgroup) is scheduled to begin meeting in November 2024. MPUC currently anticipates that Phase 3 of the proceeding will conclude with an Agenda Meeting in Fall 2025.

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[30] Minnesota Public Utilities Commission, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*, Dockets No. E002,E015,E017/CI-24-288, Notice Soliciting Stakeholder Members (September 26, 2024).

Docket No.E002/CI-24-318: In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy

On September 16, 2024, MPUC issued an Order in Xcel's 2023 Integrated Distribution Planning (IDP) docket. Order Point 14 directs MPUC's Executive Secretary "to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel," (other utilities may elect to participate in the stakeholder process), with the goal of completing the stakeholder process by July 1, 2025.[31] As stated above in the Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan* summary, Order Point 14(d) of MPUC's September 16, 2024 Order establishes that the framework should address the following topics, at a minimum:

i) *How to allocate the costs of proactive upgrades.*
ii) *How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.*
iii) *If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.*
iv) *How a proactive upgrade program would integrate with a utility's planned distribution investment programs.*
v) *How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.*
vi) *How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.*
vii) *Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).*

On September 26, 2024, MPUC opened Docket No. E002/CI-24-318, *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy* in accordance with Order Point 14 in its September 16, 2024, Order in Docket No. E-002/M-23-452. On September 26, MPUC issued a Notice Soliciting Stakeholder Members for a Proactive Grid Upgrade Workgroup, which will further develop the administrative record on this topic in fulfillment of the requirements outlined in Order Point 14.[32]

Like the process described above under Docket No. E002/CI-24-288 summary, the Proactive Grid Upgrade Workgroup will meet throughout a three-phase process.

- Phase 1 will consist of the joint meeting with the DER Cost Sharing Workgroup/Reactive Cost Sharing Workgroup, as summarized above.
- Phase 2 will focus on the topics outlined in Order Point 14 in MPUC's Order approving Xcel's IDP.
- In Phase 3, MPUC will issue a Notice of Comment in the proceeding to further develop the record on this topic. Phase 3 will be informed by prior phases in the proceeding.

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[31] Minnesota Public Utilities Commission, *In the matter of Xcel Energy's 2023 Integrated Distribution Plan,* Docket No. E-002/M-23-452, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024).

[32] Minnesota Public Utilities Commission, *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy,* Docket No. E002/CI-24-318, Notice Soliciting Stakeholder Members September 26, 2024).

The Proactive Grid Upgrade Workgroup is scheduled to begin meeting in November 2024. MPUC currently anticipates that Phase 3 of the proceeding will conclude with an Agenda Meeting in Fall 2025.

2.4 LMI-Accessible CSG Program Updates and Implementation

Legacy and LMI-Accessible CSG Program Differences

Minn. Stat. § 216B.1641, which became effective January 1, 2024, establishes the core requirements for the LMI-Accessible CSG Program, which are summarized below. Much of the language in this section is directly from either the Legacy or updated LMI-Accessible CSG statute, though the language is sometimes summarized where appropriate. For comprehensive and exact statutory language, please refer directly to Minn. Stat. § 216B.1641.

Where relevant throughout this section, key differences between the current LMI-Accessible CSG Program and the Legacy program are noted. CSG facilities approved before January 1, 2024, remain subject to Legacy program requirements; CSG facilities seeking approval after January 1, 2024, are subject to the updated program requirements.

Individual CSG Facility Size Requirements and Programmatic Capacity Limits

Facilities seeking to participate in the LMI-Accessible CSG Program cannot exceed 5 MW, an increase from the 1 MW cap under the Legacy program. To participate in the program, facilities must be connected to the utility's distribution system.

Furthermore, unlike the Legacy program, which lacked a programmatic cap, the LMI-Accessible CSG Program establishes the annual programmatic capacity limits provided in Table 4. In Table 4, the annual capacity limit applies to each year (e.g., up to 100 MW of CSGs can be approved under the program in 2024, another 100 MW can be approved in 2025, and an additional 100 MW can be approved in 2026).

Table 4: Annual maximum CSG program capacity limits (MW)

Program Years	Annual Capacity Limit (MW per program year)
2024, 2025, 2026	100 MW
2027, 2028, 2029, 2030	80 MW
2031+	60 MW

The statute directs Commerce to allocate CSG capacity based on anticipated benefits (summarized below), which—if present—the developer should identify in the CSG application. The Legacy program required that approved facilities "be consistent with the public interest," (Subd. 1(e(4))) but did not outline specific benefits intended to guide prioritization.

The LMI-Accessible CSG Program requires that Commerce prioritize allocating capacity for applications that demonstrate the following, as listed in Subd. 7(b(1)):

> *(1) the degree to which subscribers, utility ratepayers, or the community surrounding the project receive the financial benefit of tax benefits and other incentives resulting from the community solar garden;*

(2) the scale of financial benefits the community solar garden delivers to LMI subscribers, affordable housing residents, and public interest subscribers, as well as the number of, and project capacity attributable to, LMI subscribers, affordable housing residents, and public interest subscribers;

(3) community solar garden project ownership and financing arrangements that deliver benefits to public, nonprofit, cooperative, and Tribal entities;

(4) whether the community solar garden uses nongreenfield locations, especially rooftops, carports, or sites that contain a hazardous substance, pollutant, or contaminant;

(5) whether the community solar garden provides workforce development and apprenticeship opportunities, especially for workers who are Black, Indigenous, or Persons of Color; and

(6) the resiliency benefits the community solar garden provides to the electrical grid or the local community.

Facility Ownership and Subscriber Types

The updated program also establishes several different types of eligible CSG subscribers. As defined in Subd. 2 and summarized below, different subscriber types may have different ownership allowances and participation of certain subscriber types is required for CSG approval. This approach differs from the Legacy program, which did not specify requirements related to subscriber types.

- *LMI subscribers:* Subscribers that meet the definition of a low-income household as described under Minn. Stat. § 216B.2402, Subd. 16, *or* subscribers with a household income 150 percent or less of the area median income (AMI). Either must be true at the point in time that the CSG subscription was executed.
- *Public Interest subscribers:* "A subscriber that demonstrates status as a public or Tribal entity, school, nonprofit organization, house of worship, or social service provider."
- *Backup subscribers:* Subscribers who are eligible to subscribe to up to 15 percent of a facility's annual capacity "but may be automatically subscribed to up to 40 percent of the community solar garden's capacity for up to one year," in the event that another subscriber exits the CSG or is delinquent on paying bills.

These three subscriber types are distinct from the "subscriber organization," which is the entity (typically a solar developer) that owns the CSG facility.

Subscription Requirements, including LMI Requirements

Facilities seeking to participate in the CSG program must fulfill the following subscription eligibility requirements:

- Subscribers must reside in the utility's Minnesota service territory.
- No fewer than 25 individual subscribers per megawatt of generation capacity.
- No individual subscriber may subscribe to more than 40 percent of the CSG facility's total capacity.

The prohibition on an individual subscriber posing more than 40 percent of the CSG facility's total capacity presents a different approach to subscription sizing compared to the prior approach under the Legacy program. Instead of placing a percentage cap on how much of a CSG facility's capacity an individual subscriber can subscribe to, the Legacy program established that each subscription must be sized to represent at least 200 watts of the CSG facility's generating capacity. The Legacy program also placed a consumption cap on subscriptions; under the Legacy program, a CSG facility was prohibited from supplying more than 120 percent of the average annual electricity consumption of the facilities' subscribers, in combination with any other distributed generation resources that provided electricity to those subscribers.

One of the most substantial changes between the Legacy and LMI-Accessible CSG Programs is the establishment of specific CSG allocation requirements for LMI subscribers. Specifically, under the new program Commerce may only allocate capacity to a CSG if the subscription plan provided in the application ensures the following:

- LMI subscribers constitute at least 30 percent of the facility's capacity
- LMI, public interest, or affordable housing providers (combined) constitute at least 55 percent of the facility's capacity

Subscriber Compensation Requirements

Under the Legacy program, the utility was obligated to purchase electricity generated by the CSG through an alternative tariff with a bill credit compensation mechanism (subject to MPUC approval), as described in § 216B.164, Subd. 10. The updated CSG program involves a proportional bill credit approach based on the subscriber's share of the facility, and has specific rate percentage requirements by subscriber type, as shown in Table 5.

Table 5: Compensation requirements by subscriber type

Subscriber Type	Utility Purchase Requirement
LMI	Average retail rate for residential customers
Non-LMI Residential	85% average retail rate for applicable residential customers
Master-Metered Affordable Housing	80% average retail rate for residential customers
Public Interest Subscribers (small general commercial)	75% average retail rate for customer's rate class
Public Interest Subscribers (general service commercial)	100% average retail rate for customer's rate class
Commercial (other)	90% average retail rate for customer's rate class
Notes: For CSG facilities with at least 50% total capacity subscribed to by LMI customers, specific compensation requirements for backup subscribers apply.	

Subscriber Type	Utility Purchase Requirement
Unsubscribed energy generated at the facility that is credited to the subscriber organization is compensated at a rate equal to the utility's avoided cost.	

The utility is obligated to purchase electricity generated from the facility for 25 years from the start of facility operations.

Subscriber Protections and Subscriber Organization Prohibitions and Obligations

The Legacy program outlined some basic consumer protection requirements when describing MPUC's authority to approve, deny, or modify a utility-proposed CSG program. Specifically, the Legacy program established that any plan approved by MPUC must identify the information that must be provided to potential subscribers to ensure fair disclosure of future costs and benefits of subscriptions. However, the LMI-Accessible CSG Program outlines more specific consumer protection requirements for both subscribers and non-subscribers, at the CSG facility level. Additionally, the LMI-Accessible CSG Program outlines specific requirements and prohibitions for the subscriber organization (the entity that develops or owns the CSG). All subscriber, non-subscriber, and subscriber organization requirements pertaining to consumer protection are summarized below.

Subscriber protections

- CSG subscriptions are transferable within the utility's service territory.
- The subscription cost "must not exceed the value of the subscriber's community solar garden bill credit. For an LMI subscriber, the cost of the community solar garden subscription must not exceed 90 percent of the LMI subscriber's community solar garden bill credit and must not include any fees at the time the subscription is executed" (Subd. 10(b)).
- Participating utilities must offer consolidated billing (i.e., a subscriber must have the option to receive one bill for both their monthly electric service and their subscription to the CSG). Subscribers are not obligated to utilize the consolidated billing offering, but it must be available to them as an option.
- Subscribers must have an opportunity to submit comments on the subscriber organization's annual report (annual report requirements are described in greater detail below under *Prohibitions and Additional Requirements*).

Non-subscriber protections

- For utility customers that receive (or are eligible to receive) bill assistance, the utility's fuel adjustment charge cannot include net CSG facility generation costs.

Subscriber organization requirements and prohibitions

As indicated in Subd. 9, subscriber organizations and their marketing representatives are prohibited from doing the following:

> *(1) checking the credit score or credit history of a new or existing residential subscriber;*

(2) charging an exit fee to a residential subscriber;

(3) enrolling a subscriber without the subscriber's prior, voluntary consent;

(4) engaging in misleading or deceptive conduct; and

(5) making false or misleading representations.

The LMI-Accessible CSG Program contains additional consumer protection requirements, including prohibiting subscriber organizations from publicly disclosing certain subscriber information (account information, energy usage/consumption data, or bill credits) without the subscriber's written, informed consent. Additionally, both the subscriber organizations and their marketing representatives are required to provide subscribers with accurate, plain language information regarding the CSG facility and their rights as subscribers.

For further transparency, subscriber organizations must produce an annual report for each CSG facility, beginning one year after the facility becomes operational. The report must contain financial information, energy production data, and a list of who currently owns and manages the CSG facility. The report must be submitted to Commerce on a Department-provided form (currently under Department development) and must provide the report to each of the CSG's subscribers. Additionally, the subscriber organization must publish an annual report that outlines how much of the CSG facility's capacity is allotted to different subscriber categories (e.g., LMI subscribers, other residential subscribers, public interest subscribers by type, small subscriptions of up to 25kW, etc.).

Additional Requirements

Additional requirements in the updated CSG program that were not in the Legacy program include a prevailing wage requirement and a noncompliance reporting requirement.

The prevailing wage requirement establishes that facilities 1 MW or greater that seek to become approved CSG facilities must have been constructed or installed in accordance with Minnesota's prevailing wage rate requirement. This requirement is subject to relevant prevailing wage requirements and enforcement mechanisms.

The new noncompliance reporting requirement is a self-reporting requirement for CSG facilities. If a CSG facility is out of compliance with the project eligibility, capacity limit, subscriber organization prohibitions/obligations, or subscriber protections requirements established in the LMI-Accessible CSG Program, they must provide written notice of this noncompliance to Commerce within 30 days (from the point of noncompliance). If the CSG facility does not achieve compliance within 12 months, Commerce is required to revoke the CSG facility's program participation. However, past noncompliance does not prohibit the subscriber organization from re-applying to the program.

Review of Available Program Material

Commerce continues to update the public program website materials to ensure program and process clarity and to reach important LMI-Accessible CSG Program audiences. The website provides information on the goals and process of program administration. Key program detail information is available, including application requirements, interconnection agreement requirements, requirements for subscriber organizations (including verifying the eligibility of subscribers), consumer protection requirements, and additional key features.

To facilitate and streamline the application process, Commerce also includes required application forms, including the following:

- Subscription Plan Spreadsheet
- Applicant Attestation and Subscriber Organization Code of Conduct
- Subscriber Information Disclosure Form
- LMI subscriber mix reporting template

These and all other application requirements are listed on an LMI-Accessible CSG Program Application Checklist provided on the program website.

Commerce also provides a prioritization scoring rubric for applications, as informed by Minn. Stat. § 216B.1641, Subd. 5, 6, 7(c), and 10(c). This rubric is intended for use if the total capacity of project applications in the year exceeds 100 MW. In accordance with the 2023 statute, the rubric takes into account factors including incentive pass-through, financial benefits to target subscribers, ownership and financing arrangements, site location, workforce development, and resiliency benefits. Commerce additionally provides a list of program definitions and a regularly updated list of frequently asked questions about the application process.

Most of the LMI-Accessible CSG Program materials described above are developer-facing, as the program remains in its early stages, where developers have been the primary party interacting with the program. To expand program awareness among non-developer parties, Commerce launched an additional community solar garden program web page in August 2024 that targets a broader audience.

The new web page provides answers to common questions about CSGs in Minnesota, provides links to additional informational resources, and provides contact information (via email or phone) for individuals interested in subscribing to community solar.

2.6 Perceptions of the LMI-Accessible CSG Program

The report authors conducted five interviews with subject matter experts familiar with the LMI-Accessible CSG Program. In consultation with Commerce, the report authors identified stakeholder perspectives used to inform CSG program implementation. Target stakeholder perspectives included Department personnel, a residential and small business utility consumer advocate, Xcel, and CSG project developers.

The interviews consisted of semi-structured, one-hour conversations. The conversations focused on topics identified through discussions with Commerce, including (1) identifying any statutory or policy concerns, (2) providing perspective on the current experiences with LMI-Accessible CSG Program administration by Commerce, (3) soliciting any overarching program considerations as Commerce continues to address their statutory requirements, and (4) identifying opportunities for improvement in the program. The conversations sought stakeholders’ understanding of the 2023 statute and their understanding of Commerce’s roles in implementing the statute. The conversations did not seek to identify or suggest potential changes to the 2023 statute.

Minnesota Department of Commerce

Commerce noted that in its first eight months of administering the LMI-Accessible CSG Program administration, it focused on establishing processes as directed by the legislature. Because CSG applications approved before January 1, 2024, remain under the Legacy program, the 2024 LMI-Accessible CSG Program is commingled with Legacy program projects. Department personnel noted that the new and Legacy programs being intertwined in the 2024 program year was a point of some sensitivity. At the time of the interview, Commerce had approved 55 projects. Batch 1—opened on February 1, 2024—resulted in 39 MW of project approvals, while subsequent batches have resulted in less than 0.5 MW per month. At the time of the interview, Commerce had not publicly announced approved projects but noted that it anticipates potential press releases or communications surrounding approved projects under the program.

From January through August 2024, Commerce conducted public engagement regarding the LMI-Accessible CSG Program, primarily focused on communications with developers and trade associations. Commerce noted that the communications materials primarily focused on designing an effective competitive bidding process that would attract developers. Commerce set forth rules for the batch application process. The application process currently consists of batch applications, and Commerce intends to solicit batch applications monthly. Commerce seeks to keep applications open for a sufficient period of time to enable developers to apply so that Commerce can meet the program's maximum annual capacity limit.

Commerce released the initial program materials containing information on the batch process on January 2. In March, Commerce released a second batch with no major changes to communications. One change to the application was the addition of an input for the interconnection queue number for each project. Commerce also worked to improve program administration related to site control by allowing developers to provide a lease memo as proof of site control rather than requiring a full lease.

The rules Commerce created to meet statutory requirements of program administration continue to be a work in progress. Commerce actively engages parties involved in the program to improve rules and processes. Commerce noted that developers actively provide feedback. Commerce noted that Xcel is a productive partner in identifying and considering program improvements.

Commerce noted the importance of Xcel as a “major part of the puzzle” for program administration. On May 30, 2024, MPUC ordered that Xcel use its existing distributed generation portal for interconnection applications for the new LMI-Accessible CSG Program and may use or modify its existing CSG application portal once Commerce has granted capacity for proposed projects. Commerce received feedback from developers and Xcel that the development and deployment of the portal system caused significant delays in the application process. The Xcel portal was not operational until well into the 2024 program year, which delayed application processing by Xcel and subsequently Commerce. Commerce acknowledged that the regulatory requirements for the portal were complicated, and that Xcel required time to gain regulatory approval from MPUC.

Commerce is interested in learning more about interconnection issues. Department personnel expressed some concern about the approval of CSG projects while the requirements remained minimal and were still under development. Interconnection processes also can take significant time and could delay an application and threaten project approvals in a given program year.

Commerce noted that there is still work to be done related to consumer-facing portions of the statute. First, Commerce must develop rules to address subscriber organizations' prohibitions and requirements. Second, Commerce hopes to improve its understanding of the perspectives and experiences of LMI populations.

Stakeholders

Commerce directed the report authors to conduct interviews with subject matter experts to uncover quantitative and qualitative aspects of the CSG program not revealed by review of the regulatory, legislative, or other records. The report authors engaged with Department personnel to identify appropriate parties to interview. They then organized semi-structured conversations with those stakeholders seeking to understand their experiences with the new LMI-Accessible CSG Program, identify stakeholder concerns, and solicit opportunities for Commerce to improve CSG program performance.

Consumer advocate

Great Plains Institute interviewed a nonprofit advocate focused on affordable utility service, consumer protections, and clean energy (hereafter referred to as "consumer advocate"). The consumer advocate works with hundreds of Minnesotans every year on matters related to consumer rights, utility information resources, and utility service requirements. The consumer advocate focuses on equity for consumers. In addition, the consumer advocate works to help consumers identify options for accessing renewable energy.

The consumer advocate was not directly involved in the development of the 2023 legislation establishing the LMI-Accessible CSG Program. The consumer advocate's strongest interests were the provisions with direct consumer protection implications.[33] The consumer advocate noted that many other utility programs include risks associated with dishonest marketing practices. Such practices include concerns about sales pressures, misleading or deceptive practices, and unclear information about bill impacts. The consumer advocate did note that they were assured by provisions in the program that forbid enrolling in the LMI-Accessible CSG Program without consent.

The consumer advocate noted that their interpretation of the 2023 statute provided Commerce with broad authority over consumer protections associated with the LMI-Accessible CSG Program. Commerce's interpretation and enforcement of this broad authority for consumer protections is yet untested before regulators. The consumer advocate noted that the public and program stakeholders would benefit from the development of clear rules.

The consumer advocate suggested that consumers may need guidelines and publicly available information about key program questions. Commerce could serve as a non-biased source of information. Further, the consumer advocate noted that public information could be designed to answer

[33] Minn. Stat. 2023, § 216B.1641 describes consumer protection provisions in Subd. 9 (Subscriber organizations; prohibitions; requirements); Subd. 10 (Subscriber protections); and Subdivision 11 (Non-subscriber protections).

questions for LMI and other consumers to inform their decision to choose an LMI-Accessible CSG Program subscription versus or in addition to other potential consumer program options. Potential information could include:

- Clear communication of projected credits over time for subscribers
- Clear statement of any assumption of future energy costs
- Statements on the likelihood of subscriber savings
- Clarification to potential subscribers that even if rates go up or down, savings are required within the program
- Clarify the form in which the credit shows up on a consumer bill
- Potential seasonality of bill credits and eligibility for and interaction with other programs, such as budget billing.[34]

The consumer advocate expressed concerns about their understanding of how the LMI-Accessible CSG Program delivers benefits to LMI consumers. The consumer advocate expressed uncertainty regarding whether the program is analogous to other programs targeted for LMI populations that ensure bill savings.

The consumer advocate has not received a significant amount of contact from consumers in 2024 related to the LMI-Accessible CSG Program. The consumer advocate also noted that information could be developed to clarify any perceptions of interactions of the LMI-Accessible CSG Program with other LMI energy programs, such as the Energy Assistance Program.

The consumer advocate expressed concerns about several aspects of the LMI-Accessible CSG Program. One concern is that consumers may lack information on how the program delivers consumer benefits versus and/or in conjunction with other potential LMI-focused energy programs. In 2023, the Minnesota Legislature passed a 100 percent carbon-free standard (SF 4/HF 4), which requires that all investor-owned, municipal, and cooperative electric utilities in Minnesota deliver 100 percent carbon-free electricity by 2040. Solar is one of several eligible carbon-free technologies described under the statute. Many Minnesota utilities also have their own internal decarbonization goals, separate from the state's 100 percent by 2040 requirement. The consumer advocate believed that potential CSG subscribers would want to know how this LMI-Accessible CSG Program may or may not deliver unique benefits versus utility programs, including benefits from cost savings and/or access to renewable energy. In the context of the state's decarbonization policies, it was unclear to the consumer advocate how the CSG Program might deliver unique benefits related to access to renewables. Please refer to Section 4.0, *CSG Program Ratepayer Impacts* for a CSG program benefit-cost analysis (BCA).

Cooperative developer

The report authors held semi-structured interviews with two CSG project developers. One developer was a consumer-owned cooperative, nonprofit developer that focuses on developing community-based solutions in underserved and low-income communities in Minnesota (referred to as "cooperative

[34] Sec. 216B.098 MN Statutes Subd. 2. *Budget billing plans* establishes that "a utility shall offer a customer a budget billing plan for payment of charges for service, including adequate notice to customers prior to changing budget payment amounts. Municipal utilities having 3,000 or fewer customers are exempt from this requirement. Municipal utilities having more than 3,000 customers shall implement this requirement before July 1, 2003."

developer"). The other was a private developer, owner, operator, and financier of solar and storage projects, with projects in Minnesota (referred to as "private developer"). Both firms have significant experience developing projects under Minnesota's Legacy CSG program. Both have been actively engaged in regulatory and legislative discussions related to Minnesota's CSG policies, and both received Department approval for projects in the 2024 LMI-Accessible CSG Program year.

The cooperative developer works on projects exclusively for LMI populations, communities of people of color, and other populations considered to be historically marginalized and/or underserved by the provision of energy services. The cooperative developer aims to create an ownership model whereby wealth for members is created through projects that reduce energy use and/or generate clean energy.

The cooperative developer expressed a desire for Commerce to be more active in administering the LMI-Accessible CSG Program. The cooperative developer experienced frustration and a perceived lack of role clarity in the early stages of Commerce's rulemaking, leading to misunderstandings in the roles and responsibilities of program administration. In particular, the cooperative developer felt that the utility and Commerce had different perceptions of roles, and those differences caused difficulty for developers.

The perception of the cooperative developer was that the utility was acting to limit the program. The utility was required to provide a portal to process interconnection applications for projects. The implementation of the portal was delayed significantly into the program year. The cooperative developer noted significant effort was required in proceedings before MPUC related to the portal and other utility administrative roles. That effort took time and resources away from working on the 2024 program. The cooperative developer expressed concerns that the process delays and perceived utility behavior would cause the 2024 LMI-Accessible CSG Program to fall short of the annual capacity limit for project development. This is of particular concern to developers because if a given program year did not reach the annual capacity limits, the 2023 statute would not permit any rollover of capacity into subsequent years.

The cooperative developer noted multiple administrative challenges in directly engaging with the utility, multiple of which were filed within complaints to MPUC. On May 30, 2024, MPUC ordered a utility to "develop and file a standard contract governing the terms and conditions for the purchase of power exported by the CSG operator to Xcel under the non-legacy CSG program for commission approval."[35] The cooperative developer noted that the utility instead filed the standard contract—a critical element of a developer's application within the CSG process—within its tariff, which was inconsistent with the Order. By filing the tariff, the remedy required potential further regulatory actions, thus leading to potential further delays in processing applications.

The cooperative developer experienced that the portal and critical elements of the utility's administrative process were prone to errors, which caused delays. The cooperative developer would report the errors to the utility for corrections. The cooperative developer perceived significant delays in response time to error reports. The cooperative developer experienced inaccuracy within the utility's

[35] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Order Implementing New Legislation Governing Community Solar Gardens (May 30, 2024).

processing of bill credits. The cooperative developer noted that utility data systems were not able to provide sufficient usage data as required by the program, which added 2-3 extra steps to the process. The cooperative developer felt the current structure places a significant onus on the developer to document utility system problems. The cumulative experience of the cooperative developer is frustration with the utility management of critical aspects of the administrative processes for developers within the LMI-Accessible CSG Program.

The cooperative developer praised Commerce for working directly to address programmatic issues or concerns. The cooperative developer sees Commerce as very responsive and attentive to important issues.

The cooperative developer noted Commerce's rules and procedures for LMI subscriber verification are challenging. Commerce changed certain verification processes while subscriber organizations (such as the cooperative developer), including forbidding self-attestation of LMI eligibility. This change posed challenges for subscriber organizations that were then required to re-engage with subscribers they previously contacted, and to add new processes to their approach with new subscribers.

The cooperative developer identified that one barrier to program participation is the program's income verification processes. Potential subscribers are required to provide the subscriber organization with information to demonstrate income eligibility, which the subscriber organization uses for their own CSG application to Commerce to demonstrate that their facility would meet the required LMI carve-out requirements. The cooperative developer noted that this onerous verification process can directly interfere with the target customers' (i.e., LMI households) willingness to participate in the program, as trust can be poor between these potential LMI subscribers and the other entities with program responsibilities (i.e., developers, utilities, and governmental institutions). The cooperative developer noted a concern that continued additional steps and additional information required of LMI subscribers would have a negative impact on their ability to gain project subscribers. For example, the current process requires that LMI subscribers attest to the number of taxpayers that live in their household. For LMI populations, this number can fluctuate. The cooperative developer also noted that the LMI communities are accustomed to predatory behavior and may experience the verification requirements as a potential threat. More plainly stated, the concern is that "onerous" administrative burdens can easily overwhelm the likelihood of recruiting subscribers from LMI populations that the program aims to serve.

The cooperative developer believes that Commerce has a strong role to play in improving the experience of LMI subscribers. The cooperative developer suggested simplifying the subscriber experience by designing a single form containing all of the subscriber verification requirements.

Their assertion is that Commerce has a role in better calculating the bill credits to reflect the value of the resource. The cooperative developer spoke extensively about the limitations of the current process by which bill credits are calculated. Their belief is that the current bill credit process fails to value the critical benefits of CSG. The cooperative developer argued that there are significant benefit streams that are not appropriately addressed within the bill credit regime. Among the benefits the cooperative developer named were locational benefits of distributed generation for resilience, an undervaluing of the social cost of carbon used to calculate greenhouse gas benefits, community wealth-building, and the inappropriate use of wholesale electricity pricing embedded in the average retail rate for residential customers. The cooperative developer notes that a number of these elements were contained in the VOS rate previously discussed within the Legacy CSG program. The cooperative developer acknowledges some of the benefits are challenging to calculate, but believes the VOS provided Commerce and stakeholders a means of discussing approaches to valuation of bill credits. The cooperative developer believes that Commerce can improve communication of the values of CSGs before MPUC.

Private developer

The report authors interviewed a private developer that had developed over 100 projects totaling over 200 MW_{dc} of solar capacity, with over 100 MW of solar gardens in operation or development in Minnesota. The private developer participated in the Legacy program and received Department approval for projects in 2024. Across projects, private developer analysis revealed that the company enabled over $8M in subscriber savings in Minnesota. The private developer had been directly engaged in regulatory and legislative discussions related to CSG over many years.

The private developer experienced the first year of the LMI-Accessible CSG Program as a process of "identifying and overcoming a lot of hurdles." The private developer attributed success in addressing program issues to active engagement across stakeholders.

The private developer praised Commerce for its leadership in administering the new program. One example the private developer provided was related to a nuance in co-location. Developers and the utility were able to work with Commerce to continue past practices from the Legacy program, providing practicality and continuity in expectations. The private developer also called out the benefit of Commerce's current practice of allocating projects via a monthly batch process. The private developer stated their experience with the application process in 2024 has been positive. The private developer found Commerce's program application process to be very transparent. They felt that Commerce's communication of the program's objective of the process was clearly explained to applicants in the materials. The private developer mentioned that Commerce maintained an effective stakeholder feedback process in 2024.

The private developer identified challenges related to Commerce's rules and expectations for verification of LMI subscribers. The private developer expressed a concern that gaining LMI subscribers is challenging and is a "labor of love." Commerce policy requires tax documents and other verification methods. While the private developer acknowledged some steps were necessary, their concern was that additional requirements do impose administrative burdens on prospective LMI subscribers. These administrative burdens increase costs to potential subscribers and the subscriber organizations. In addition, the private developer stated that additional burdens tended to lower the likelihood of LMI enrollment.

The private developer noted some other jurisdictions in which self-attestation of LMI status is accepted and further noted that the Coalition for Community Solar Access (CCSA) outlined self-attestation of income as a best practice. The private developer provided examples of income verification processes from other jurisdictions, which will be covered in the final report under Subtask 1.2. The private developer was able to obtain lists of LMI individuals from community action groups in Colorado. These lists improved their efficiency in gaining LMI subscriptions. The private developer identified tools, such as the National Renewable Energy Laboratory's Clean Energy Connector to help identify relevant LMI populations for subscription recruitment. The Clean Energy Connector is "a digital tool that state governments can use to help stakeholders in their states securely connect LIHEAP recipients with community solar subscriptions that provide meaningful electric bill savings Stakeholders using the Connector include state community solar and LIHEAP program offices, community solar subscription managers, and local LIHEAP administrators."[36] At the time of this report, the tool was piloted in the District of Columbia, Illinois, and New Mexico.

The private developer felt Commerce's process for project solicitation was practical. The current practice of Commerce is that first qualifying projects are accepted (first-come, first-served), then when project application levels exceed the annual capacity limit for the program year, statutory prioritization kicks in. The private developer anticipated that future program years may reach the application limit much earlier in the program year than what occurred in 2024. Further, many of the projects in the application pool for 2024 include projects under the Legacy rules, which include a capacity size limit of 1 MW per project. The new program allows for project sizes up to 5 MW. Both the increased experience of applicants in the Minnesota program and the increased size limits for projects in the new program will impact applications in future rounds. The private developer anticipates Commerce will be much more active in the project prioritization process in future years as the application levels will exceed the program capacity levels more quickly in future program years.

The private developer expressed frustrations with utility interconnection. The private developer was involved in regulatory matters surrounding interconnection and experienced the delay in implementation and availability of the utility's required interconnection portal as detrimental to their prospects and the program. A signed interconnection agreement must exist between the utility and a developer in order for the project to apply for Department approval within the program. The private developer said interconnection studies often take 9-12 months before an interconnection agreement is reached. The private developer said that the utility's delays in implementing the portal for the interconnection process caused them to doubt that the 2024 program year would result in enough projects to achieve the annual program capacity limitation.

The private developer identified challenges associated with the billing and bill credit process involving developers, subscribers, and utility billing. The private developer said the current program requires them to work to verify if the utility bill credits are being paid, and they often don't have a true way to audit if the bill credit function is working. According to the private developer, a developer either has to request the information or respond to a subscriber complaint to the subscription organization—otherwise, there's no clear process for subscriber organizations to identify if/how bill credits are being administered as required.

The private developer was concerned that the utility is not directly incentivized to help the program succeed beyond compliance with the requirements in the statute. The private developer acknowledged that the utility has been a transparent partner and noted comparatively positive interactions compared to other utilities they worked with in other CSG programs. The private developer was unable to identify any incentive for the utility to improve any aspect of the program. The private developer had concerns

[36] "Clean Energy Connector," NREL, https://connector.nrel.gov/.

about whether there would be sufficient incentive for a utility to appropriately invest in resources and staff to improve aspects of the program.

The private developer offered potential opportunities for program improvements. First, the private developer identified that consolidated billing remains an outstanding issue for consumers. The private developer believed there remains uncertainty about how best to go about communicating the bill credits to LMI subscribers and encouraged accountability for utilities that were experiencing errors in providing bill credits. Second, the process for verification of LMI status for program eligibility should be simplified. The private developer believed that the process for identification and recruitment of LMI customers is less burdensome in other jurisdictions compared to Minnesota. For example, the private developer suggested Commerce consider partnering with other energy assistance programs to identify potential populations eligible for program benefits. Lastly, the private developer noted that the program did not consider co-location of energy storage and solar. The private developer believed the Minnesota Distributed Energy Resource Interconnection Process and Agreement (MN DIP and DIA) process could work together with the LMI-Accessible CSG Program to deliver greater benefits to consumers and the grid.

Xcel Energy

Commerce sought the perspective of the utility with statutory responsibilities as outlined in the LMI-Accessible CSG statute—Xcel. Xcel is involved in regulatory and legislative matters related to CSG and administers parts of the CSG project application process within the LMI-Accessible CSG Program. Xcel's primary responsibility under the new program is to manage interconnection processes. Xcel is required to verify an interconnection agreement prior to sending applications to Commerce for consideration. Xcel maintains a public website with information on program details, how to contact a CSG developer, and how to develop solar gardens.

Xcel acknowledged statutory challenges to implementing the new program, noting that the new statute interacted with other statutory and regulatory requirements. Xcel expressed frustration with the limited amount of time between the law passing and implementation of the new program and felt that there was insufficient time to address regulatory matters before MPUC prior to program implementation. Further, the overlap of the Legacy program and the new program in the 2024 program year posed regulatory and implementation challenges. The new program required changes to tariffs in order to accommodate new program elements. Xcel noted that the statute requires that the utility incur the costs of Department administration and stated that there was still a lack of clarity regarding how to directly tie program costs to utility regulatory cost recovery processes.

Xcel faced challenges in creating, implementing, and improving the use of its CSG portal. Many of the fixes to information errors or system issues were manual. Xcel acknowledged that the delays in the opening of the portal caused confusion, but expressed that overall, processing applications through the portal was successful. Xcel anticipates that the program's annual capacity limit will be reached by fall.

Xcel anticipates a queue problem over time because projects may gain Department approval, but not necessarily in the same order in which they fall in the interconnection queue. There is potential for interactive effects as multiple projects could be proposed on a site in combination with varying positions in the queue. Relatedly, Xcel expressed concern that the cost allocation framework, through which a first-mover project is responsible for all upgrade costs, did not seem to anticipate a way to deal with combinations of future projects that may benefit from upgraded locational hosting capacity. This first-mover pays policy poses a risk for free ridership for subsequent projects.

Xcel appreciated Commerce's willingness to have open communication as program issues arose. Xcel and Commerce held frequent meetings to discuss implementation issues and acknowledged Commerce's work to improve public-facing program information in response to frequently asked questions by posting a FAQ on Commerce's website. Xcel also noted that Department personnel are asking good questions.

Xcel believes that Commerce could improve the program by further developing consumer-facing information. Xcel does not have insight into how subscribers will change over time as that is not a utility responsibility. Xcel wished to know how Commerce may review subscriber changes over time and noted Commerce's role as an unbiased source of information for the public and potential subscribers. Xcel stated that it would be helpful for Commerce to develop unbiased material so that the utility personnel responsible for customer relations are better prepared to answer any questions about the program.

Xcel noted opportunities for improvement as Commerce continues to modify the new program. Xcel encouraged the continuation of regular meetings regarding program administration and noted that Commerce is in a unique position to improve communication and connection between the utility and developers. Xcel also appreciated the feedback from developers about any errors or issues with the program.

Summary of CSG Program Stakeholder Perspectives

Commerce established productive partnerships for program administration and improvements. Each stakeholder noted that Commerce is both proactive in communicating changes to program administration and/or rules and responsive in adjusting to stakeholder perspectives and feedback. Department personnel are trusted to serve as an independent administrative authority alongside program participants and utilities. All stakeholders valued the open lines of communication to Commerce for discussion of any program issues.

Commerce helped clarify roles within the program, and more could be done. Multiple stakeholders noted that role clarity is important for program success. Most stakeholders offered an understanding that Commerce, program participants, and utilities were "building the airplane as they were flying it." All parties noted that an important role will be how Commerce forms and improves rules associated with consumer protections. At the time of this report, the majority of Commerce's focus has been on communicating clearly to the community of developers and utilities. All stakeholders noted that Commerce's role is to clarify the expectations of subscriber organizations as they enroll subscribers. LMI populations are particularly vulnerable to misleading marketing and messaging. Commerce's rules on clarifying roles and expectations should also be flexible, given the unique challenges of enrolling LMI populations.

Commerce should expand LMI-Accessible CSG Program communications for consumers. Most program communications in the early stages of 2024 are targeted toward developers. All stakeholders noted a need to create clear communications materials for potential subscribers. Utilities and developers noted a need for a trusted and unbiased source for prospective subscriber information. Stakeholders suggested content that included information related to consumer rights, expected subscriber benefits, expected savings, and ways to evaluate the LMI CSG program alongside or in comparison to other energy assistance programs. The consumer advocate noted a perceived lack of information from an unbiased source that could be used to help consumers understand the potential benefits and risks of CSG subscriptions.

Income verification for prospective LMI subscribers was challenging and imposed potential enrollment risks. Developers and the consumer advocate noted that LMI populations were unlikely to enroll in programs that require onerous verification processes. Commerce's income verification processes in the 2024 program year underwent changes. Subscriber organizations had to return to subscribers to request additional information. Those additional requests were reported by developers as negative consumer experiences. Commerce was interested in ensuring that the verification process for the LMI-Accessible CSG Program was aligned with other LMI programs offered through state agencies, including energy assistance programs through Commerce. Developers, both of which served as subscriber organizations, noted that the changes to the income verification process throughout the 2024 program year caused confusion with consumers and could have caused subscribers to lose trust in the program and/or forgo enrollment. Developers offered suggestions to improve these processes, including acceptance of self-attestation, which is seen as a best practice for income verification.

Developers and utilities expressed differing opinions on the implementation of the 2024 program year. Developers are concerned that the LMI-Accessible CSG Program will result in levels of projects reaching the annual capacity limit for the 2024 program year. The Utility believed that reaching the annual capacity limit for the 2024 program year was likely. The disconnect of information and perspectives appeared to result from the differing information parties received within the current program administration.

The developers viewed the significant delays in Xcel's implementation of the interconnection portal as potentially strategic. Xcel viewed the delays as necessary to meet its regulatory obligations. Xcel viewed their regulatory obligations under the new 2024 CSG program were not fully anticipated in the 2023 legislation. Xcel viewed the initial issues as an unfortunate, unintentional, and common part of changes to regulated programs. Overall, developers defined program performance as (a) achievement of program annual capacity limits, and (b) administrative ease of program activities. The Utility viewed the program performance as (a) compliance with statutory and regulatory requirements, and (b) administrative ease of program activities.

Commerce can learn from other jurisdictions. Consumer advocate, developers, and Xcel all expressed interest in learning from the approaches of other jurisdictions with LMI CSG programs. From the interviews, it seems a number of comparative analyses are warranted, including but not limited to the following:

- Roles of parties within the program, including utilities, developers, subscriber organizations, and low-income advocacy organizations
- Program administration details, including the design of government-led project solicitation processes
- Technical and interconnection policies that govern similar CSG programs

- Processes for verification of income for LMI populations
- Practices for consumer-facing communications

Many of the issues stakeholders identified in the interview process are included in the comparative analyses in subsequent sections of this report.

3.0 Comparative Analysis of LMI Community Solar Programs in Other Jurisdictions

Methodology

Commerce requested a cross-jurisdictional comparison of the LMI-Accessible CSG Program with similar programs operated in other jurisdictions. The report authors conducted the comparison, which includes program structure(s), the manner in which applications are submitted and reviewed, how related infrastructure upgrades are prioritized and funded, and how regulations and penalties are structured. The report authors examined several components (where available/applicable) related to each of these categories:

- General program structure
- Program budget and/or costs
- Fees, costs, activities born by developers and/or utilities
- Utility accountability and oversight
- Program capacity
- LMI requirements and/or incentives for developers
- LMI definitions and eligibility
- LMI savings requirements
- Subscriber costs or fees
- Consumer protections

To conduct the cross-jurisdictional analysis, report authors conducted a literature review of best practices compiled from national analyses alongside a review of state-specific policies, regulations, and program materials. Prior to issuing an RFP for this report in the spring of 2024, Commerce conducted a Request for Information (RFI) soliciting stakeholder input on report topics. This RFI solicited jurisdictions appropriate for review, which Commerce identified within the RFPs for this report. The report authors discussed additional jurisdictions to consider with Commerce. The report authors' cross-jurisdictional review considered the following programs:

- Colorado Community Solar Gardens Act
- District of Columbia Solar for All
- Illinois Solar for All
- Solar Massachusetts Renewable Target (SMART) Program
- Maryland Community Solar Energy Generating Systems Program
- Maine Net Energy Billing (NEB)
- New Jersey Community Solar Energy Program
- New Mexico Community Solar Program

- New York Sun Solar Program
- Oregon Community Solar Program
- Virginia Shared Solar Program

Finally, to complement the research, the report authors conducted interviews with subject matter experts representing state community solar program administrators, consumer advocates, and community solar industry players.

Key Takeaways and Recommendations

The following section summarizes key points of comparison from other jurisdictions along with recommendations for Department consideration pertaining to program capacity limits, prioritizing capacity allocations, subscription and LMI requirements, LMI income definitions and income verification processes, consumer-facing information and materials, and subscriber protections. Detailed analyses that informed these recommendations can be found below in the Cross-Jurisdictional Program Review section.

Program Capacity Limits

The Minnesota LMI-Accessible CSG Program establishes annual programmatic capacity limits of 100 MW in 2024-2026, 80 megawatts in 2027-2030, and 60 MW in 2031 and after.

Cross-Jurisdictional Comparison

The program caps for the Minnesota LMI-Accessible CSG Program fall within the range of capacity limits for other jurisdictions included in the cross-jurisdictional comparison. Select programs are summarized below in Table 6.

Table 6: CSG program caps in other jurisdictions

Select Programs	Community Solar Cap
Minnesota LMI-Accessible CSG Program	No program-wide cap; cap established by program year. • 100 MW annual cap for 2024–2026 program years • 80 MW annual cap for 2027–2030 program years • 60 MW annual cap for 2031 and all subsequent program years
Maine Net Energy Billing	750 MW
Solar Massachusetts Renewable Target	3200 MW (includes both residential and community solar)
New Jersey Community Solar Energy Program	500 MW
New Mexico Community Solar Program*	200 MW
Oregon Community Solar Program	160 MW
Virginia Shared Energy Solar Program†	400 MW

Notes:

*In October 2024, the New Mexico Public Regulation Commission (PRC) adopted amendments to New Mexico's Community Solar Rule (17.9.573 NMAC) that expand the program's capacity to 500 MW total, with the 300 MW of additional capacity available beginning November 1, 2024.

†Includes total capacity for both the expanded Shared Solar Program in Dominion Energy territory and the new Shared Solar Program in Appalachian Power (APCo) territory.

Recommendation

To respond to changing market conditions, Minnesota may wish to consider a more flexible approach to capacity limits. Such a change would not be in the direct purview of Commerce; rather, it would require the legislature to amend Minn. Stat. § 216B.1641, Subd. 3-14. Over time, capacity blocks or incentives may be adjusted as market conditions change. For example, the Massachusetts SMART program currently uses predetermined capacity blocks with declining base compensation rates, and SMART program staff have proposed an annual adjustable block and rate structure to allow for annual adjustments based on market trends and progress toward program goals.

Process(es) for Allocating Capacity for CSG Projects

The Minnesota LMI-Accessible CSG Program prioritizes applications that demonstrate various financial and non-financial benefits, such as tax and financial incentives for subscribers, capacity dedicated to LMI participants, land use, workforce and apprenticeship opportunities, and resiliency benefits.

Cross-Jurisdictional Comparison

As displayed in Table 7, the report authors' review of other jurisdictions' application processes reveals some overlap with Minnesota's approach to prioritizing capacity allocations, particularly with regard to siting and land use factors. Fewer states have developed prioritization criteria based on community and resilience benefits, which can be more difficult to quantify. However, the Massachusetts program staff have proposed a new Community Benefits adder for the SMART program to encourage community engagement and partnerships with community-based organizations and local leaders.

Table 7: CSG capacity allocation approaches in other jurisdictions

Select Programs	Application Process and Prioritization
Solar Massachusetts Renewable Target	Project selection is based on a competitive procurement process through which the distribution utilities develop a request for proposals in consultation with Commerce of Public Utilities. Any unawarded remaining capacity is distributed on a first-come, first-served basis. In the 2024 straw proposal, program staff propose allocating capacity for large project applications received in the first 10 business days based on the Interconnection Services Agreement execution date and then allocating any remaining capacity on a rolling basis.

Select Programs	Application Process and Prioritization
New Jersey Community Solar Energy Program	After an initial 10-day period, applications are reviewed on a first-come, first-served basis. Only projects 5 MW or less that are installed at certain types of sites (rooftops, floating solar, carports/canopies, contaminated sites and landfills, and mining sites) are eligible.
New Mexico Community Solar Program	Bids are scored based on a competitive RFP, which may include non-price factors such as subscriber mix, community and local benefits, partnerships with tribal or local organizations, labor arrangements, and cultural affairs.
Virginia Shared Energy Solar Program	Capacity is distributed on a first-come, first-served basis.

Recommendation

Commerce could consider implementing clear scoring criteria and weights, particularly for metrics that may be difficult for applicants to quantify, such as resiliency or other community benefits. New Mexico's Community Solar Program's 2022 RFP may offer a model for prioritizing "non-price" criteria such as subscriber mix, LMI discounts, workforce training and education, contracts with local or minority-owned businesses, and partnerships with community- and tribe-based organizations.

Subscription and LMI requirements

The Minnesota LMI-Accessible CSG Program differentiates among three categories of subscribers: LMI subscribers, public interest subscribers (such as public or tribal entities, schools, nonprofit organizations, houses of worship, and social service providers), and backup subscribers. The program requires that subscribers reside in the utility's Minnesota service territory, requires no fewer than 25 individual subscribers per megawatt of generation capacity, and prohibits any individual subscriber from holding more than 40 percent of the facility's total capacity. Commerce may only allocate capacity to a CSG if the subscription plan provided in the application ensures that LMI subscribers constitute at least 30 percent of the facility's capacity and LMI, public interest, or affordable housing providers (combined) constitute at least 55 percent of the facility's capacity.

Cross-Jurisdictional Comparison

The 30 percent LMI carve-out required under the LMI-Accessible CSG Program is in line with other jurisdictions' LMI carve-outs for community solar, summarized below in Table 8. Of the eleven jurisdictions analyzed, eight have an LMI carve-out. Some jurisdictions in the report authors' review define carve-outs according to program capacity, while others define it by individual project nameplate capacity, block capacity, or project output.

Table 8: Comparison of LMI carve-outs by jurisdiction

Select Programs	LMI Carve-Out
Minnesota LMI-Accessible CSG Program	All projects must reserve at least 30% of project capacity for low- and moderate-income households.

Select Programs	LMI Carve-Out
Colorado Community Solar Gardens Act	Each qualifying retail utility must reserve at least 5% of the renewable energy it purchases from CSGs for eligible low-income CSG subscribers.
Maryland Community Solar Energy Generating Systems Program	All projects must reserve 40% of project output for LMI subscribers.
Virginia Shared Energy Solar Program	All projects must reserve at least 30% of project capacity for low-income customers or low-income service organizations.
New Jersey Community Solar Energy Program	All projects must reserve at least 51% of project capacity for LMI subscribers.
New Mexico Community Solar Program	All projects must reserve at least 30% of project output for low-income customers and low-income service organizations.
Oregon Community Solar Program	All projects must reserve at least 10% of project capacity for low-income subscribers for the Interim and Second Offerings.
Solar Massachusetts Renewable Target	5% of each capacity block is set aside for low-income community shared solar or low-income properties. To receive the Low-Income community Shared Solar adder, at least 50% of the energy output must be allocated to low-income customers.
NY-Sun (Inclusive Community Solar Adder)	40% of total project capacity must go to income-eligible subscribers, and no less than 50% of the ICSA portion of the project capacity must go to income-eligible residential subscribers.

Recommendation

As the Minnesota LMI-Accessible CSG Program matures and continues to compile data on the percentage of capacity each project is reserving for LMI subscribers, Minnesota could consider increasing the LMI carve-out or providing additional incentives and/or preference to projects that serve a higher percentage of LMI subscribers. Increasing the carve-out would place Minnesota in line with other leading community solar states, such as New York and New Jersey, whose carve-outs are up to 50% of individual project capacity.

LMI Definitions and Income Verification Processes

The Minnesota LMI-Accessible CSG Program defines LMI subscribers as subscribers whose income is 150 percent or less than AMI. To verify a subscriber's income level, subscriber organizations can request a tax return or proof that the household is categorically eligible, such as their participation in another income-eligible program administered or approved by Commerce, including the Weatherization Assistance Program and the Low-Income Home Energy Assistance Program (LIHEAP).

Cross-Jurisdictional Comparison

About half of the jurisdictions reviewed for the cross-jurisdictional analysis define "low income" as 80 percent AMI or 80 percent state median income. Other states define it based on the federal poverty level or tie income eligibility to eligibility for other government income-based programs. In addition to offering categorical eligibility as a means of verifying income, some states have worked to further streamline the verification process using geo-eligibility (location in a disadvantaged community or low-income area), self-attestation, or automatic enrollment for LIHEAP-qualified households.

Recommendation

To help ease the burden for low-income households and subscription organizations, Minnesota could consider providing additional pathways for verifying eligibility, such as geo-eligibility, self-attestation, or automatic enrollment of beneficiaries of income-qualified programs. While only two states (New Jersey and—as of October 2024—New Mexico) allow for self-attestation as a method for verifying income, additional states are considering it. Industry representatives also support this method, particularly as a way to reach households that are not eligible for federal benefits (such as non-US citizens)—but are eligible to subscribe to CSGs—or households that may be eligible for programs like LIHEAP but are unable to participate due to funding constraints. To prevent fraud, Commerce may consider limiting self-attestation to specific types of applicants (for instance, those residing in disadvantaged communities, residing in low-income census tracts, or enrolled in categorically eligible programs.

Consumer-facing materials and information

Commerce recently updated the LMI-Accessible CSG Program website to include information for consumers, including a list of consumer rights, instructions for how to sign up, a list of participating vendors, and contact information for filing a complaint.

Cross-Jurisdictional Comparison

Most states have developed consumer-facing materials or websites to provide information about their community solar program. In addition to the type of information Commerce has included, other states have also developed frequently asked questions pages, video explainers, fact sheets and brochures, and disclosure form deep dives. A few states also provide program resources in languages other than English.

Recommendation

As the program expands, Commerce can include additional program resources for consumers and update resources to best meet consumer needs. Commerce can build from or adapt resources developed in other states and may need to hire staff or contract with a firm to ensure language accessibility and cultural relevance.

Subscriber protections

Minnesota's LMI-Accessible CSG Program outlines several strategies for protecting subscribers, including (1) allowing subscriptions to be transferable and portable, (2) ensuring the subscription cost does not exceed the value of the bill credit (and does not exceed 90 percent of the bill credit for LMI subscribers), (3) requiring utilities to offer consolidated billing as an option to subscribers, and (4) providing subscribers with an opportunity to submit comments on the subscriber organization's annual report.

The program also prohibits developers from checking credit scores, charging an exit fee, enrolling a subscriber without their consent, and making false claims or engaging in deceptive conduct. Additionally, subscriber organizations are required to provide information about the contract terms in clear, easy-to-understand language and must fill out and provide the subscriber with the program's Subscriber Information Disclosure Form.

Cross-Jurisdictional Comparison

Table 9 below provides a cross-jurisdictional overview of Minnesota's CSG program subscriber protections compared to approaches implemented in other jurisdictions.

Table 9: Comparison of Minnesota's subscriber protections, versus approaches in other jurisdictions

State	Disclosure Form or Standard Contract Terms	Marketing Guidelines	Language Access	No-Cost Cancellation	Complaint Process	LMI Savings Requirement
Minnesota	X	X		X	X	X
Colorado	X		X			X
Maryland	X					
Virginia	X				X	
New Jersey	X				X	X
New Mexico	X	X	X		X	
Oregon	X	X	X	X	X	X
District of Columbia	X		X	X	X	X
Massachusetts	X				X	X
Maine	X					
New York	X	X		X		X
Illinois	X	X	X		X	X

Recommendation

To build on the LMI-Accessible CSG Program's existing subscriber protections, Commerce could develop additional marketing guidelines to clarify expectations for what might be considered a misleading claim or deceptive conduct. Commerce may also consider developing consumer-facing resources in languages other than English and hiring a dedicated staff person to monitor complaints and ensure compliance with the consumer protection requirements.

Cross-Jurisdictional Program Review

The following section offers further detail on how various jurisdictions have approached key community solar policy and program design questions, including program structure(s), the manner in which applications are submitted and reviewed, how related infrastructure upgrades are prioritized and funded, and how regulations and penalties are structured.

Program Structure

LMI community solar program structures vary across the county. One common format is the block structure, through which a certain number of megawatts in specific utility territories are designated for the program (and thus usually able to receive incentives such as attractive compensation rates and/or adders) through blocks of capacity. Several states have used their program success to expand capacity blocks. For instance, in April 2024, the New Jersey Board of Public Utilities announced an additional capacity block of 275 MW after the initial capacity block of 225 MW became fully subscribed.

States may also pair their capacity blocks with varying levels of incentives. Program incentives may decline incrementally as blocks become fully subscribed. Over time, the incentives may be phased out as market conditions become more favorable to solar. According to New York's NY-Sun program, which uses this type of structure, declining incentive blocks are "designed to support solar markets in the areas where support is needed most and decrease incentives as they become less necessary to a self-sustaining solar market."

The Massachusetts SMART program currently uses predetermined capacity blocks with declining base compensation rates. However, SMART program staff have proposed to transition the program to an annual adjustable block and rate structure by which base compensation rates, capacity blocks, and incentives can be adjusted annually up or down depending on market conditions and progress toward solar targets. The straw proposal also recommends unlimited capacity and streamlined applications for projects smaller than 25 KW. Notably, staff recommendations would also eliminate separate adders and eligibility criteria for market-rate community solar versus low-income community solar. It would also require that all shared solar projects enroll a minimum of 40 percent low-income customers who would receive a minimum 20 percent discount compared to basic service.

Some jurisdictions structure their CSG program to have a public agency serving as the key interface between developers and subscribers.

For instance, in the District of Columbia, developers are able to retain Solar Renewable Energy Credits (SRECs) as an incentive to build community systems for the District's program. The developers then assign the energy generated to the District Department of Energy and Environment (DOEE) at no cost. DOEE then delivers the energy generated to low-income Solar for All subscribers.

According to the North Carolina Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency (DSIRE), Washington, D.C.'s SREC prices at $400 per MWh are among the most generous in the country. D.C.'s program is not bound by capacity caps but rather has a goal to serve 100,000 LMI households by 2032. In addition to the SRECs, the program also provides participating developers with a capacity-based incentive whose level is determined during an annual RFP process (capped at $1.25 per watt). During the annual RFP process, each bidder proposes a rate at which they are offering to include each project in the program. Together with the SRECs and federal tax incentives, this capacity-based incentive helps cover the full cost of project development, operation, and maintenance.

Program Budget and Source(s) of Funding

There is limited publicly available information on CSG program administration budgets. Cost estimates range from approximately $150,000 to pay for the time of regulatory agency personnel in Maine (as outlined in LD 936, An Act to Amend State Laws Related to Net Energy Billing and the Procurement of Distributed Generation) to nearly $1.5 billion for the multi-faceted NY-Sun program, which covers administrative costs, subsidies, adders, and other solar funding in New York (as approved by the New York Public Service Commission's Order Expanding the NY-SUN Program in April 2022).[37] Programs in between, which may more closely resemble Minnesota's, include the Solar for All program in D.C. (costing $1,979,122 from D.C.'s Renewable Energy Development Fund for personnel services according to the Fiscal Year 2022 Annual Report) or New Mexico's program, which is estimated to cost approximately $500,000 per year per the Public Regulation Commission's Adopting Rule in 2022.

While the examples above draw on fixed program administration costs embedded in annual budget requests, some states cover program administration costs through fees applied on projects and/or subscribers. In Oregon, program administration is fully funded by the application fees ($5/kW$_{AC}$ for the Interim Offering) and program fees which include both the utility fee (varies by utility from $0.11/kW$_{AC}$ to $0.48/kW$_{AC}$) as well as the program administrator fee ($0.85/kW$_{AC}$). As detailed in the Oregon program's Billing and Payments Guide for Project Managers, program fees are collected monthly and depend on the size of each subscription, and low-income subscriptions are exempt from the program fees. Program fees can also be updated each year through a process that the Oregon Public Utility Commission oversees.

Utility Cost Recovery

According to the Smart Electric Power Alliance, community solar programs may cause utilities to incur unanticipated costs. Possible sources of these costs include grid impacts (interconnection, transmission, etc.), pre-program marketing and administration (IT infrastructure, updated billing, etc.), unsubscribed generation from a solar project built or contracted for the program and stranded assets stemming from

[37] State of New York Public Service Commission, *In the Matter of the Advancement of Distributed Solar*, Docket No. 21-E-0629, Order Expanding NY-Sun Program (April 14, 2022).

participation in the community solar program. The jurisdictions reviewed in this report employ various strategies to enable utilities to recover these costs.

Some of the jurisdictions examined allow utilities to file interconnection cost-sharing proposals for review by regulators. For instance, Colorado's 2024 Access to Distributed Generation bill (SB24-207) allows any investor-owned utility with more than 500,000 customers to file updates to tariffs to implement interconnection cost-sharing for system upgrades "whereby a community solar facility only pays the facility's proportional share of newly created hosting capacity associated with the facility." New Mexico's Adopting Rule allows the New Mexico Public Regulatory Commission to make decisions about cost-sharing for necessary distribution system upgrades on a case-by-case basis. Costs may be shared across the subscriber organizations connected to the same distribution system, across all ratepayers for the utility, or across all ratepayers in the same class as the subscribers for the project. The Adopting Rule also instructs the Commission to use the same analysis used to determine cost-sharing for grid modernization projects when determining whether there are public benefits to cost-sharing.

Maine's Net Energy Billing program provides for costs and benefits incurred or realized by utilities to be reviewed by the Maine Public Utilities Commission annually for inclusion in the utility's stranded cost rates. According to the Commission's rule on Customer Net Energy Billing, eligible costs and benefits include incremental administrative costs, payments or bill credits, and revenue from the monetization of the output of the eligible facility.

All participants in the Solar Massachusetts Renewable Target Program (SMART) are charged a "Distributed Solar Charge," which helps pay for enhancements to solar energy delivery, efficiency, and availability; improvements in solar billing, metering, and program implementation; and incentivizing Massachusetts residents to go solar.

LMI Requirements and Incentives for Developers

Many states use a combination of requirements and incentives to encourage participating developers to reach LMI customers. For instance, as displayed below in Table 10, most states with LMI programs require an LMI carve-out and provide specific benefits, such as guaranteed bill savings or a discounted subscription fee.

Table 10: Required LMI Carve-Out by jurisdiction

Select Programs	LMI Carve-Out
Minnesota LMI-Accessible CSG Program	All projects must reserve at least 30% of project capacity for low- and moderate-income households.
Colorado Community Solar Gardens Act	Each qualifying retail utility must reserve at least 5% of the renewable energy it purchases from CSGs for eligible low-income CSG subscribers.
Maryland Community Solar Energy Generating Systems Program	All projects must reserve 40% of project output for LMI subscribers.
Virginia Shared Energy Solar Program	All projects must reserve at least 30% of project capacity for low-income customers or low-income service organizations.

Select Programs	LMI Carve-Out
New Jersey Community Solar Energy Program	All projects must reserve at least 51% of project capacity for LMI subscribers.
New Mexico Community Solar Program	All projects must reserve at least 30% of project output for low-income customers and low-income service organizations.
Oregon Community Solar Program	All projects must reserve at least 10% of project capacity for low-income subscribers for the Interim and Second Offerings.
Solar Massachusetts Renewable Target	5% of each capacity block is set aside for low-income community shared solar or low-income properties. To receive the Low-Income community Shared Solar adder, at least 50% of the energy output must be allocated to low-income customers.
NY-Sun (Inclusive Community Solar Adder)	40% of total project capacity (including market-rate subscribers) must go to income-eligible subscribers, and no less than 50% of the ICSA portion of the project capacity must go to income-eligible residential subscribers.

In some states, developers may receive bonuses or adders to their solar compensation rate—or an advantage when bidding for a portion of the capacity allocation. For example, New York's program offers developers an Inclusive Community Solar Adder (up to 20 cents/watt) if they dedicate at least 40 percent of project capacity to income-qualified subscribers and at least 50 percent to eligible residential subscribers.

Other states have developed community solar programs or sub-programs designed to serve LMI customers only. For example, eligibility for Washington, D.C.'s Solar for All program is limited to District households with incomes at or below 80 percent AMI. Similarly, the Illinois Solar for All program requires all subscribers to be income-eligible, except for an anchor tenant. However, according to the program's Approved Vendor Manual, projects can receive additional points during the Illinois Solar for All selection process if located in an environmental justice or low-income community or if the anchor tenant is a nonprofit or public facility.

LMI Definitions and Income Verification Processes

While specific low-income definitions for community solar programs may vary, many states define "low-income" based on AMI, state median income, or percentage below the poverty level. For example, New Mexico, Virginia, the District of Columbia, and Illinois define income-eligible households as households with incomes at or below 80 percent AMI, and Oregon and Colorado use 80 percent state median income. For Maryland's community solar program, "low income" is defined as having an annual household income at or below 200 percent of the federal poverty level, while "moderate income" is defined as an annual household income at or below 80 percent state median income. Maryland also ties low-income eligibility to eligibility for any other federal, state, or local income-based assistance program.

State programs also tend to vary in terms of the income verification methods allowed to qualify a subscriber as low or moderate income. In addition to the traditional method of requiring pay stubs or tax returns—which may create an insurmountable barrier for some lower-income subscribers—most states now offer some form of categorical eligibility, through which a potential subscriber only needs to provide proof that they already participate in another low-income program (such as LIHEAP, Weatherization Assistance Program, Supplemental Nutrition Assistance Program, Temporary Assistance for Needy Families, or other state or utility income-assistance programs). Some states, like New York and Massachusetts, also verify income eligibility based on the customer's location in a disadvantaged community or low-income area (i.e., "geo-eligibility"). Similarly, residence in an affordable housing property can serve as proof of income eligibility for subscribers in New Mexico, Massachusetts, and New York.

A few states have explored alternative verification methods to further simplify the process for households. For example, the District of Columbia's Solar for All program (which does not charge any fees or subscription costs) automatically enrolls customers who qualify for LIHEAP, and Oregon's program has a Low-Income Facilitator who helps each low-income household verify their income.

Consumer advocate and industry representatives interviewed for this report both recommended states consider self-attestation as a method for verifying income to further reduce both the burden on low-income households as well as the cost and liability for developers to safely store sensitive income documentation. Interviewees also emphasized the need to align with the Treasury Department and the Internal Revenue Service's guidance on the Low-Income Communities Bonus Credit program, which allows for self-attestation (indirectly) if it is allowed in the jurisdiction where the project is located.

Currently, New Jersey offers self-attestation to verify income, and self-attestation is under consideration for the New Mexico Community Solar Program. In a special report examining opportunities to reduce fraud in the Home Electrification and Appliance Rebates program authorized by the Inflation Reduction Act of 2022, the US Department of Energy's Office of the Inspector General characterizes "self-certifying income [as] an easy entry point for fraudulent claims to be submitted" and recommends limiting the option to specific applicants such as those residing in disadvantaged communities, residing in low-income census tracts, or enrolled in categorically eligible programs.

Subscriber Protections

As federal, state, and private investments in solar continue to grow and access to community solar expands, instances of deceptive marketing tactics and other unscrupulous conduct by a small subset of bad actors in the solar industry have increased. In response, many states have incorporated various strategies, procedures, or requirements into their community solar programs to protect consumers and ensure a positive experience for program participants, particularly for households experiencing low incomes.

In most states, consumer protections rely heavily on standard disclosure forms as well as rules governing contract terms, marketing, and opt-out or cancellation processes. Many states have eliminated upfront program fees and long-term contracts and provide subscribers with rescission periods to cancel their participation with minimal or no penalties. Several states have also established complaint processes and forms, and at least one state conducts annual compliance checks and randomized audits to ensure compliance with consumer protections. Table 11 summarizes the consumer protections required by the state community solar programs analyzed for this report, and the subsequent sections offer additional detail and examples of states' consumer protection strategies.

Table 11: Consumer protection provisions in select community solar programs in other jurisdictions

State	Disclosure Form or Standard Contract Terms	Marketing Guidelines	Language Access	No-Cost Cancellation	Complaint Process	LMI Savings Requirement
Minnesota	X	X		X	X	X
Colorado	X		X			X
Maryland	X					
Virginia	X				X	
New Jersey	X				X	X
New Mexico	X	X	X		X	
Oregon	X	X	x	x	X	X
District of Columbia	X		X	X	X	X
Massachusetts	X				X	X
Maine	X					
New York	X	X		X		X
Illinois	X	X	X		X	X

Marketing Guidelines

Several states have adopted marketing guidelines or requirements to protect consumers against misleading marketing claims and ensure the program is represented accurately.

In the Illinois Solar for All program's *Approved Vendor Manual*, the Illinois Power Agency outlines key requirements for marketing materials and branding, as well as suggested talking points and social media language developers can use when describing the program. The guide also provides examples of acceptable and unacceptable statements about key aspects of the program, including renewable energy credits, savings, and eligibility. The Illinois Solar for All program also requires participating vendors to submit their marketing materials for review by the Program Administrator four weeks before distributing them through a process described in Section 7.6 of the Approved Vendor Manual.

While the Oregon Community Solar Program does not vet developers' individual marketing materials, the Program Implementation Manual states that participating developers must submit a customer acquisition and marketing plan as part of the pre-certification process, and all marketing materials must include the program-approved marketing disclaimer. The Oregon program also has a Project Manager Code of Conduct outlining marketing and sales requirements to which participating developers must agree.

In addition to providing guidance on how developers and subscription managers can market projects to potential subscribers, states have also developed consumer-facing website content and explainers to educate customers and help them make informed decisions when choosing whether to participate in the community solar program and when considering offers from different developers.

For example, Illinois Solar for All has a Consumer Education and Resources web page that includes program brochures, factsheets, and a "deep dive" resource that walks customers through each portion of their disclosure form—all of which are available in English and Spanish. In Oregon, the Subscriber Resources website offers customers a number of educational resources, including a Glossary of Terms, explainers on "What to Expect After Signing a Contract" and "Understanding Your Bill," as well as specific resources for low-income subscribers. While the New Mexico Community Solar Program is still in its early stages, the program website has a Program Flyer with consumer tips and a list of questions consumers should ask the Subscription Manager and/or make sure they understand before signing a contract.

Enforcement Mechanisms and Complaint Processes

Several states have developed procedures for enforcing consumer protection requirements and addressing customer complaints. Some states, such as Oregon, provide customers with a form to file complaints. Other programs, such as the District of Columbia's Solar for All, New Mexico's Community Solar Program, and Illinois Solar for All, provide an email address and direct phone number to call with questions or concerns. Illinois also publishes a Consumer Complaint Report on a regular basis, which includes the name of the vendor, type of complaint, and complaint status (in progress, resolved, or closed). Additionally, the Illinois Solar for All Consumer Protection Complaints website outlines specific actions the program administrator can take in response to consumer protection violations, including a warning letter, requiring corrective actions, suspension from the program, and permanent expulsion from the program.

The Massachusetts Department of Energy Resources (DOER) conducts annual compliance checks as well as occasional audits to ensure that program participants comply with regulations and guidelines. Every year, system owners must provide updated customer disclosure forms for any new customers under the state's community shared and low-income community shared solar tariff. In 2021 and 2022, DOER conducted an audit of 15 projects selected at random. The final audit reports determined eight applicants to be in compliance and the remaining seven to have instances of noncompliance. Of these, two companies were suspended from submitting applications to the SMART program for 12 months as they were found to have three or more instances of noncompliance. DOER posts the results of audits, including lists of suspended entities and entities with warnings, publicly on its website. In an interview, DOER shared that one dedicated staff member spends nearly all of their time on the annual compliance reviews and audits. The consumer advocate interviewed also recommended having at least one dedicated staff person to track market activity and monitor and address complaints.

In addition to the state examples described above, the National Consumer Law Center (NCLC) developed a report (*Community Solar: Expanding Access and Safeguarding Low-Income Families*) to help guide state policymakers. Pages 4-5 of NCLC's report lists recommendations for community solar consumer protections. The recommendations fall into the following five categories:

- Financial protections,
- Marketing protections,

- Compliance protections,
- Eligibility and enrollment protections, and
- Low-income coordination.

The NCLC recommendations—as written in NCLC's report—are listed below in Table 12.

Table 12: NCLC community solar consumer protection recommendations

Consumer Protection	NCLC Recommendations
Financial Protections	• States must require marketers to ensure verifiable bill savings, provide a no-cost exit clause in contracts, and prohibit marketers from including unreasonably long contract terms, flat fees, late payment fees, termination fees, and sign-up fees. • State administrators must develop a robust process to monitor and evaluate bill savings and ensure compliance with consumer protections. • State administrators must implement consolidated billing so that households do not receive separate bills for their community solar subscription, and all program costs and credits are included on their electric bill monthly.
Marketing Protections	• States must: require marketers to make all documents available electronically, if so requested, and in paper format before a subscriber signs; provide all documents in a potential customer's primary and/or preferred language; use standardized marketing materials and disclosure forms; and ensure responsiveness to customers. • State administrators must: develop standardized plain language and concise contract considerations and disclosure forms for use by marketers; establish a Code of Practice for marketing, especially for door-to-door and telephone sales; and develop standardized consumer education materials. Noncompliance must not be tolerated and must result in consequences.
Compliance Protections	• States must require marketers to comply with the state's Code of Practice and consumer protection act, inform subscribers about complaint mechanisms, and track and report monthly to the state administrator complaint data, including but not limited to the number of complaints filed and resolved. • State administrators must: develop an accessible complaint mechanism, including explicit information about how it will resolve complaints; establish data collection protocols; develop protocols for protecting customer privacy; and, create a Code of Practice to ensure that marketers comply with relevant consumer laws.
Eligibility and Enrollment Protections	• States must require marketers to adhere to the state administrator-provided eligibility determinations and enrollment processes. Households must not be rejected based on additional criteria from the marketer. • State administrators must develop an income eligibility determination process coordinated and/or streamlined with the Low-Income Home Energy Assistance Program (LIHEAP), Weatherization Assistance Program (WAP), and/or other income-tested programs. This includes: developing methods to determine

Consumer Protection	NCLC Recommendations
	eligibility for low-income households not receiving LIHEAP; creating a system for managing waitlists; and ensuring the community solar program complements and coordinates with existing low-income energy and bill assistance programs.
Low-Income Program Coordination	• States must require marketers to develop community solar programs that are compatible and adhere to the low-income energy assistance programs identified by the state and do what is necessary to make changes if their program has adverse impacts on low-income benefits and utility allowances. • State administrators must ensure program compatibility with low-income energy assistance programs, such as LIHEAP and U.S. Department of Housing and Urban Development-assisted housing, to avoid adverse impacts on low-income benefits and utility allowances.
Source: Recommendations from pages 4-5 of the NCLC's report (*Community Solar: Expanding Access and Safeguarding Low-Income Families*)	

Billing, Crediting, and Utility Oversight

Across all community solar programs analyzed, electric utilities are responsible for delivering community solar generation credits to participating customers through their monthly utility bills. Several programs also require electric utilities to offer consolidated billing, through which the community solar generation credit and any subscriber fees or charges are both incorporated into the customer's monthly utility bill. Table 13 below summarizes state requirements and policies regarding consolidated billing as of September 2024. While both consumer advocates and the community solar industry tend to support consolidated billing because it eliminates the need for participants to pay two separate bills and offers customers a simpler, more transparent way to track their bill savings each month, successful implementation of consolidated billing relies on accurate and efficient utility billing processes.

Table 13: Cross-jurisdictional comparison of consolidated billing requirements and policies (September 2024)

State	Consolidated Billing Requirement
Illinois	Utility consolidated billing required if requested by the project owner/operator for utilities with 200,000 customers or more
Maryland	Utility consolidated billing required if requested by the subscriber organization
Minnesota	Utility consolidated billing required if requested by the subscriber
New Jersey	Utility consolidated billing required for all projects, third party-consolidated billing disallowed
New York	Utility consolidated billing required to be offered
Oregon	Utility consolidated billing required, third-party consolidated billing disallowed

State	Consolidated Billing Requirement
Virginia	Utility consolidated billing required if requested by the subscriber organization

As a result, several states have developed oversight mechanisms and processes to ensure participating utilities deliver bill credits and incorporate subscription charges in a timely and accurate manner. Establishing greater transparency through reporting requirements and open communication channels can help program administrators monitor billing processes and address issues upfront.

For example, in Maryland, House Bill 908 states that utilities will be required to report billing and crediting errors to the Maryland Public Service Commission on a regular schedule. The program also imposes specific deadlines for when bill credits (and any rollover credits) must be applied to subscribers' bills. In New Jersey, the Board Order that established the permanent program requires the creation of a community solar billing working group to bring together representatives from electric utilities, the New Jersey Board of Public Utilities, subscriber organizations, and developers to provide a forum for regular information exchange and to discuss billing process improvements.

In some states, utility commissions have used monetary penalties to enforce compliance with consolidated billing requirements. The District of Columbia's Public Service Commission responded to a petition filed by the Office of People's Council and the District Office of the Attorney General regarding the systematic mishandling of community solar charges and credits with Order No. 21600 in April 2023, which requires the utility to pay ratepayers $800,000 and requires the Commission staff to select an auditor to oversee the process of reconciling billing and metering issues. In New York, several high-profile billing issues have led to an ongoing docket with the New York Public Service Commission, including a recent staff memo[38] that proposes a $10 per month bill credit for failure to provide bill credits on time, as well as quality assurance protocols and quarterly reporting on metrics such as "(1) Billing and Crediting Accuracy; (2) Accuracy of the Total Value of the Credits Earned Across the Service Area; (3) Accurate Application of Billing Credits; (4) Customer Complaints Regarding Transfer, Billing, and Crediting Timelines; (5) Utility Response Time to Allocation Lists; and (6) Utility Response Time to Host Communications."

[38] New York State Department of Public Service, *In the Matter of Consolidated Billing for Distributed Energy Resources*, Docket No. 19-M-0463, Department of Public Service Staff Proposal on Community Distributed Generation Billing and Crediting Performance Metrics and Negative Revenue Adjustments (January 16, 2024).

Table 14: Cross-jurisdictional comparative analysis

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
CO	Colorado Community Solar Gardens Act	The community solar program established by the Colorado Community Solar Gardens Act of 2010 is split across the state's two investor-owned utilities, Xcel Energy (through the Solar*Rewards Community program) and Black Hills Energy, and overseen by the Colorado Public Utilities Commission. Both utilities allocate capacity through a competitive RFP process, in addition to a Standard Offer program option. Under the new program established by Senate Bill 24-207, inclusive community solar capacity will be allocated on a first-come, first-served basis. However, projects sited on rooftops, parking lots, brownfields, and other preferred locations will be given priority.	None found.	According to the rules adopted by the Colorado Public Utilities Commission, each qualifying retail utility must reserve at least 5% of the renewable energy it purchases from CSGs for eligible low-income CSG subscribers. Under the new program established by Senate Bill 24-207, starting in 2026, Xcel Energy must make 50 MW of "inclusive community solar capacity" available, and Black Hills Energy must make 3.5 MW available. To qualify as inclusive community solar, a garden must reserve 51% of generation capacity for income-qualified subscribers.	Per the rules adopted by the Colorado Public Utilities Commission, households are considered income-qualified if the household income is at or below 185% of the federal poverty line. The rules allow for categorical eligibility through the Colorado Low Income Energy Assistance Program. Under the new program established by Senate Bill 24-207, income-qualified subscribers are defined as households making up to 200% of the federal poverty line or up to 80% of the Colorado median income.	Senate Bill 24-207 requires the Colorado Public Utilities Commission to adopt a standard disclosure form that must: "disclose future costs and benefits of subscriptions; disclose key contract terms; provide grievance, enforcement, and cancellation procedures; provide other relevant information pertaining to the subscriptions; and must be offered in English, Spanish, and when appropriate, Native American or Indigenous languages."	None found.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
DC	DC Solar for All	DC Solar for All is managed by DOEE and offers both community solar and single-family rooftop solar for low-income District households. Capacity varies annually based on program funding. Projects apply for a capacity-based incentive through an annual RFP process. The incentive rate is determined through the bidding process, in which each project proposes a rate.	The total program budget for FY22 was $12.97 million, including $1,979,122 for DOEE personnel (according to the Fiscal Year 2022 Annual Report). Funding was sourced from the American Rescue Plan Act and through the Renewable Energy Development Fund, which is funded by Alternative Compliance Payments made by Pepco.	Solar for All is only available for households with incomes below 80% AMI (DC Solar for All webpage).	Households with income below 80% AMI are eligible. Households that apply and qualify for LIHEAP are automatically enrolled in Solar for All. Categorical eligibility is also available through additional low-income programs. Otherwise, DOEE will verify through paystubs, tax returns, or social security statements. If the household has no income, the household can fill out a form.	The program has a hotline managed by DOEE, a list of approved contractors, protections for residents of HUD-assisted multifamily properties, no fees or costs to participate, clear terms and conditions that are the same for every subscription, and free cancellation at any time. The Office of People's Council also helps District residents with issues related to companies attempting to mislead customers and can report violations to the Attorney General.	In 2023, the DC Public Service Commission issued an order in response to complaints about bill crediting inaccuracies and delays. The order directs the Commission staff to select an auditor to oversee Pepco's metering and billing reconciliation process.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
IL	Illinois Solar for All	Illinois Solar for All (ILSFA) is operated by the Illinois Power Agency and administered by Elevate. Community solar developers apply and are vetted to become Approved Vendors who can receive Renewable Energy Credit (REC) incentives and offer subscriptions to income-eligible households. Entities must apply to register as an Approved Vendor, Designee, or Single Project Approved Vendor and be approved by the Program Administrator to participate in the program and receive the REC incentive. Each application has a maximum score, and some questions have a minimum score that if not met can disqualify the applicant. The Approved Vendor application includes several questions including information about the project, the location and community served by the project, a community engagement and subscriber outreach plan, consumer protections, and plans to meet job training requirements. Applicants must also sign an attestation form and be pre-qualified under the Illinois Adjustable Block Program.	The program is funded by the Renewable Energy Resources Fund (RERF) and utility-held funds from Renewable Portfolio Standard riders. The 2024 Long-Term Renewable Resources Procurement Plan in Illinois allows the RERF to provide up to $16.5 million to fund ILSFA sub-programs (including the Community Solar program). According to the Approved Vendor Manual, the “utility-held Renewable Portfolio Standard funds were collected from ratepayers through dedicated bill riders for funding renewable energy resources. P.A. 102-0662 allows for the transfer of $50 million from the utility-held funds annually to fund ILSFA... REC contracts are funded solely with one or the other funds, with a spending priority placed on utility-held funds."	As stated in the Approved Vendor Manual, for ILSFA's Community Solar Program, all subscribers must be income eligible. However, the project can have one anchor tenant who is not income eligible. Projects can receive additional points if the anchor tenant is a nonprofit or public facility or Critical Service Provider (including affordable housing providers), or if the project is located within an Income-Eligible Community (census tract with majority of households at 80% or less AMI) or Environmental Justice Community (according to the IL EJC map).	Income eligible is defined as at or below 80% AMI. A subscriber can have their income verified before or after the referral process, either by the Approved Vendor or the Program Administrator. The Program Administrator offers three ways to verify income: (1) Categorical eligibility through third-party qualifying program (i.e., LIHEAP), (2) Income verification through a credit reporting agency, or (3) Income Affidavit (for certain circumstances). See the Approved Vendor Manual for additional details.	ILSFA has a standard disclosure form that Approved Vendors are required to provide to participants, a consumer protections manual, a complaint process (including a public list of in-progress and resolved complaints), contract requirements, marketing guidelines, a savings guarantee, "deep dive" resources to help customers understand each part of the disclosure form, and stringent requirements for vetting developers. The savings guarantee ensures subscription costs and fees cannot exceed 50% of the value of the bill credits applied to the customer’s electric bill, and there are no upfront costs. The Illinois Power Agency also has a Consumer Protection Working Group.	None found.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
MA	Solar Massachusetts Renewable Target (SMART) Program	SMART is a declining block program that provides a tariff-based incentive paid directly by the utility company to the system owner. As stated in 225 CMR 20.02, the program has a total capacity limit of 3200 MW, which is allocated among four investor-owned utilities proportionally based on size (Eversource, MA Electric, Nantucket, Unitil) and divided into capacity blocks. The capacity limit is inclusive of rooftop and community solar. Projects apply through CLEAResult and must provide: a fully executed Interconnection Service Agreement; evidence of approval from the property owner; electric account information; project design specs; the town's solar bylaws; zoning restrictions; non-agricultural, agricultural, critical habitat, previous development, or other land use as appropriate; non-ministerial permits (i.e., from local Conservation Commission), Federal Energy Regulatory Commission (FERC) Form 556 for projects greater than 1MW; design plans and permits for building-mounted; floating, canopy, brownfield, public entity, tracking, pollinator, storage, and landfill as appropriate.	None found.	Per 225 CMR 20.02, each capacity block must have a minimum of 5% of its total available capacity dedicated to Low Income Community Shared and Low Income Property Solar Tariff Generation Units Community solar serving at least 50% low-income customers. These projects receive an added 6 cents/kWh; low-income community solar projects less than 25 kW will receive 230% of the base compensation rate.	MA SMART defines low-income customers as end-use consumers on a low-income discounted rate of a Distribution Company or a resident in a Low Income Eligible Area, which is also defined in 225 CMR 20.02 as “a neighborhood, as identified through American Community Survey data, that has household income equal to or less than 65 percent of the statewide median income for Massachusetts.” Any public housing authority in Massachusetts meets the eligibility criteria to qualify as low- or moderate-income housing. For private housing at least 25% of the housing available at the properties to be served by the Generation Unit is required to be rented to households that are at or below 80% of the area median income (AMI), or at least 20% of the housing available at the properties to be served by the Generation Unit is required to be rented to households that are at or below 50% of the AMI.	During enrollment, customers must be provided with an example of potential savings, consistent with the Guideline on SMART Consumer Protection, and the Guideline Regarding Low Income Generation Units; clear and understandable information regarding the electricity rate or value of anticipated credits associated with participation in the Low Income Community Shared Solar Tariff Generation Units (LICSS) or Community Shared Solar Tariff Generation Units (CSS) system. Customers must also receive a statement explaining the claims participating customers may make, primarily that they will (1) support solar development through enrollment in the program, and (2) increase the amount of solar energy consumed by all electric ratepayers in the Commonwealth. This statement should also explain the settling of Renewable Energy Credits (RECs), and how REC ownership impacts the ability to make any claims to using solar energy.	Applicants must provide demonstration of net savings to low-income customers, including such evidence as rate comparisons, proof that bill credits or electricity are delivered each month to the customer at no cost to the customer, and thus resulting in a net reduction in the customer’s total electricity bill. DOER-led audits select projects at random for annual examination; some project sponsors in noncompliance may be suspended from the program.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
MD	Community Solar Energy Generating Systems Program	Developed and overseen by Maryland's Public Service Commission, carried out by investor-owned utilities as well as municipal and cooperative utilities. There is no cumulative capacity limit, but each project's capacity is limited to no more than 5 MW (per House Bill 908). Applicants must apply to the Public Service Commission, which determines admission to the program.	No total budget found. All costs associated with small generator interconnection standards are the responsibility of the subscriber organization.	There must be a 40% LMI carve-out for each project, based on project output (House Bill 908).	Per House Bill 908, low-income is defined as "having an annual household income at or below 200% of the federal poverty level" or "being certified as eligible for any federal, state, or local assistance program that limits participation to households with income at or below 200% of the federal poverty level." Moderate-income is defined as a household with an annual income at or below 80% of the State Median Income.	While House Bill 908 does not provide details on subscriber protections, the pilot program required subscriber organizations to use a Community Solar Contract Disclosure Form, which must include information about the subscription price and any fees (including any early cancellation fees), as well as the subscription type, and the estimated date by which credits will appear on the customer's utility bill.	House Bill 908 requires the Maryland Public Service Commission to adopt consolidated billing regulations by July 1, 2025, including a rule requiring that utilities "report billing and crediting errors to the Commission on a regular schedule" and follow "specific timing requirements for the application of bill credits to subscriber bills and the application of rollover credits."

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
ME	Net Energy Billing (NEB)	NEB has a kWh credit program that provides any electric utility customer participant a credit for every kWh provided to the grid from their solar array, and a tariff rate program for non-residential electric utility customers who can receive credits at a rate determined annually by the Maine Public Utilities Commission (PUC). NEB is a dual billing system, with subscription costs charged separately from the utility bill. The capacity limit for the program is 750 MW total (as outlined in LD 936). The maximum capacity of a community solar project is 5 MW, and the minimum is 2 MW. The application process varies based on project sponsor.	Enabling legislation provides funding for one utility analyst position and related other costs; in 2022-23, $154,192 was appropriated for the PUC (as outlined in LD 936, An Act to Amend State Laws Related to Net Energy Billing and the Procurement of Distributed Generation).	No specific LMI requirements, incentives, or provisions.	None.	The Attorney General and PUC enforce consumer protections for solar. As outlined in the Public Utility Commission's rules establishing the Net Energy Billing Program (Chapter 313), subscribers have the right to cancel their community solar agreement (orally or in writing) until five days after receipt of the first bill or invoice from the solar company. Consumers cannot be disconnected due to subscription nonpayment. The solar company can seek to collect any unpaid charges similar to any other creditor but may not impose excessive fees or penalties beyond the costs of collection. Entities that market projects to residential or small commercial customers must be registered with the PUC. Entities marketing projects to residential and small commercial customers must provide those customers with an NEB Disclosure Form that includes information on the costs and benefits of the project to the customer.	No explicit mechanisms; subscriber complaints may be fielded by PUC or Attorney General.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
NJ	New Jersey Community Solar Energy Program	The New Jersey Community Solar Energy Program (CSEP) is managed by the New Jersey Board of Public Utilities (NJ BPU) and provides incentives to eligible community solar facilities through an annual capacity allocation divided across the state's four investor-owned utilities. The program has a capacity limit of 500 MW_{dc}. Project eligibility is limited to community solar facilities $5MW_{dc}$ or smaller that are installed at certain types of sites (rooftops, floating solar, carports/canopies, contaminated sites and landfills, and mining sites). CSEP has a registration portal, where developers can apply for a portion of the capacity block. After an initial 10-day period, applications are reviewed on a first-come, first-served basis until the capacity block is fully subscribed or until June 1, 2025.	No total budget found. However, the Board Order states that utilities are allowed to fully recover the additional costs incurred to implement the program (subject to review by New Jersey Board of Public Utilities).	Per the 2023 NJ BPU Order Launching the Community Solar Energy Program, all projects must reserve at least 51% of capacity for LMI subscribers.	The program defines low- and moderate-income subscribers as households with incomes at or below 80% of the AMI. Categorical eligibility and self-attestation are allowed per the 2023 NJ BPU Order Launching the Community Solar Energy Program. Income verification is required at the time of subscription, if the subscriber changes utility accounts, and every five years.	The program has a disclosure form, complaint process and form, list of registered subscriber organizations, and guaranteed bill savings.	The 2023 NJ BPU Order Launching the Community Solar Energy Program required the creation of a community solar billing working group, including representatives from NJ BPU, utilities, subscriber organizations, developers, and other stakeholders to discuss and develop strategies to improve the billing process and establish clear lines of communication across parties.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
NM	New Mexico Community Solar Program	Statewide capacity-limited program overseen by the New Mexico Public Regulatory Commission with allocations for the state's investor-owned utilities. The program has a capacity limit of 200 MW_{ac}. The Public Regulatory Commission determines criteria for selection, developers submit bids through the Program portal, and the program administrator (InClime) selects projects. In October 2024, the New Mexico Public Regulation Commission (PRC) adopted amendments to New Mexico's Community Solar Rule (17.9.573 NMAC) that expand the program's capacity to 500 MW total, with the 300 MW of additional capacity available beginning November 1, 2024.	According to the Public Regulation Commission's Order Adopting Rule (Docket No. 21-00112-UT), the annual cost to administer the program is estimated to be $500,000, which will be covered by application fees.	As outlined in the Adopting Rule, each project must reserve a 30% carve-out for low-income subscribers and low-income service organizations (based on project output).	Per the Program Guidebook, low income is defined as at or below 80% AMI. Categorical eligibility is allowed through Medicaid, SNAP, LIHEAP, first-time homeowner programs and housing rehabilitation programs, living in a low-income/affordable housing facility, and state and federal income tax credit programs. Otherwise, income documentation must be provided.	The program has a disclosure form, complaint resolution process, a consumer protection best practices guide, as well as consumer protection resources for individual consumers and low-income service organizations. New Mexico also has a Low-Income Working Group.	None found.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
NY	NY-Sun Solar Program	The New York State Energy Research and Development Authority (NYSERDA) NY-Sun program currently has two main pathways for low-income community solar: Solar for All (SFA) and a declining block Community Adder program with an additional Inclusive Community Solar Adder (ICSA). Solar for All capacity is fully subscribed in most regions of the state; NYSERDA's 2023 Annual Report notes that the project will soon no longer be active. ICSA capacity depends on the region—860 MW for upstate; and 100 MW for Con Ed, as outlined on NYSERDA's ICSA webpage. For SFA, applicants apply directly with NYSERDA. The online application requests name, household information, utility account number, rent vs. homeowner status, and referrals. For ICSA, applicants apply directly with project sponsor, and the application process varies by sponsor.	NY-Sun's annual funding (includes SFA, Community Adder, ICSA, and other solar funding) budget is $1.474 billion, as approved by the New York Public Service Commission's Order Expanding the NY-SUN Program in April 2022. In 2020, funding for NY-Sun was $573 million, of which $111 was for the Community Adder.	To receive the ICSA Adder (up to 20 cents/watt), projects must be metered as community distributed generation; dedicate no less than 40% of the project capacity (W_{dc}) to Eligible Subscribers and dedicate no less than 50% of the ICSA portion of the project capacity (Wdc) to eligible residential subscribers. A minimum 10% bill credit discount rate is required; to receive community benefits bonus, a minimum 15%-20% bill discount is required for all ISCA-eligible subscribers.	As outlined in the Program Manuals, Solar for All and ICSA allow categorical eligibility (through EmPOWER, HEAP, SNAP, TANF, Supplemental Social Security); geo-eligibility (based on location in a disadvantaged community); regulated affordable housing rental eligibility income (80% AMI); and eligibility for nonprofit/public facilities serving disadvantaged communities. ICSA-eligible non-residential subscribers include nonprofit and public facilities serving disadvantaged communities; public schools; and affordable housing facilities.	Consumer protections, marketing/advertising, and disclosures are governed by the New York Public Service Commission's Uniform Business Practices for Distributed Energy Resource Suppliers.	As part of an ongoing docket within the NY Public Service Commission, a January 2024 staff memo proposes metrics to incent improvement to Community Distributed Generation billing processes as well as a $10 per month bill credit for failure to provide bill credits in a timely fashion, quarterly reporting of billing and crediting performance, and quality assurance protocols.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
OR	Oregon Community Solar Program	Statewide capacity-limited program overseen by the Oregon Public Utility Commission with allocations for Oregon's three investor-owned utilities: Portland General Electric, Idaho Power, and Pacific Power. The program has a capacity limit of 161 MW_{ac} as outlined in the Program Implementation Manual. To apply, the Project Manager must submit a pre-certification application, which is reviewed by the Program Administrator and approved by the Oregon PUC. The Project Manager must then develop the project, pass utility and jurisdictional inspections, and subscribe at least 50% of the Project capacity before requesting certification. The Program Administrator then reviews the project, and the Oregon PUC certifies the project (no later than 18 months after pre-certification). The project then completes interconnection and inspections and must begin operation within six months after certification.	Program administration is fully funded by the application fees ($5/$kW_{AC}$ for the Interim Offering) and program fees (utility fee of $0.11/$kW_{AC}$ to $0.48/$kW_{AC}$ plus Program Administrator fee of $0.85/ kW_{AC}). The Billing & Payments Guide for Project Managers provides additional details on program fees and application fees.	As outlined in the Program Implementation Manual, 10 percent of each project's capacity must be owned or leased by low-income participants. Projects with at least 50% of capacity reserved for low-income participants are eligible to receive an allocation from a carve-out.	Low income is defined as at or below 80% state median income. As stated in the Program Implementation Manual, income verification is conducted by the program's Low-Income Facilitator.	The program has a complaint form/process, Program Manager Code of Conduct, marketing guidelines, educational resources for households, a standard contract template (available under Project Manager Resources on the program web page), and requirements for specific contract provisions.	None found.

State	Program Name	Program Structure (capacity limits, application process)	Program Budget, Source(s) of Funding, and Distribution of Costs	LMI Requirements and/or Incentives for Developers	LMI Definitions and Income Verification Processes	Subscriber Protections	Billing, Crediting, and Utility Oversight
VA	Virginia Shared Solar Program	The Shared Solar Program is overseen by the State Corporation Commission and only applies to Dominion Energy, requiring subscribers to become customers of Dominion. The program has an overall capacity limit of 150 MW with facility generating capacity limited to 5 MW, as stated in the Virginia State Corporation Commission's Rules Governing the Shared Solar Program. Third-party subscriber organizations must register and apply for program capacity, which is awarded on a first-come, first-served basis.	None found.	As outlined in the Virginia State Corporation Commission's Rules Governing the Shared Solar Program, there is a 30% carve-out for low-income customers.	Per the Virginia State Corporation Commission's Rules Governing the Shared Solar Program, low-income is defined as "any person or household whose income is no more than 80% of the median income of the locality in which the customer resides."	Subscriber organizations must provide customers with a completed copy of the Virginia Shared Solar Program Consumer Disclosure Form developed by the Virginia State Corporation Commission. The Disclosure Form must include key contract terms, including any early termination or cancellation fees, the subscription type and billing mechanism, a summary of all subscription charges and other fees, and an example calculation of subscriber bill savings as well as the estimated date the savings will show up on the customer's bill.	The Rules Governing the Shared Solar Program require subscriber organizations to "retain customer billing and account records and complaint records for at least three years and provide copies of such records to a customer or the commission upon request."

4.0 CSG Program Ratepayer Impacts

Overview of Benefit-Cost Analysis Results

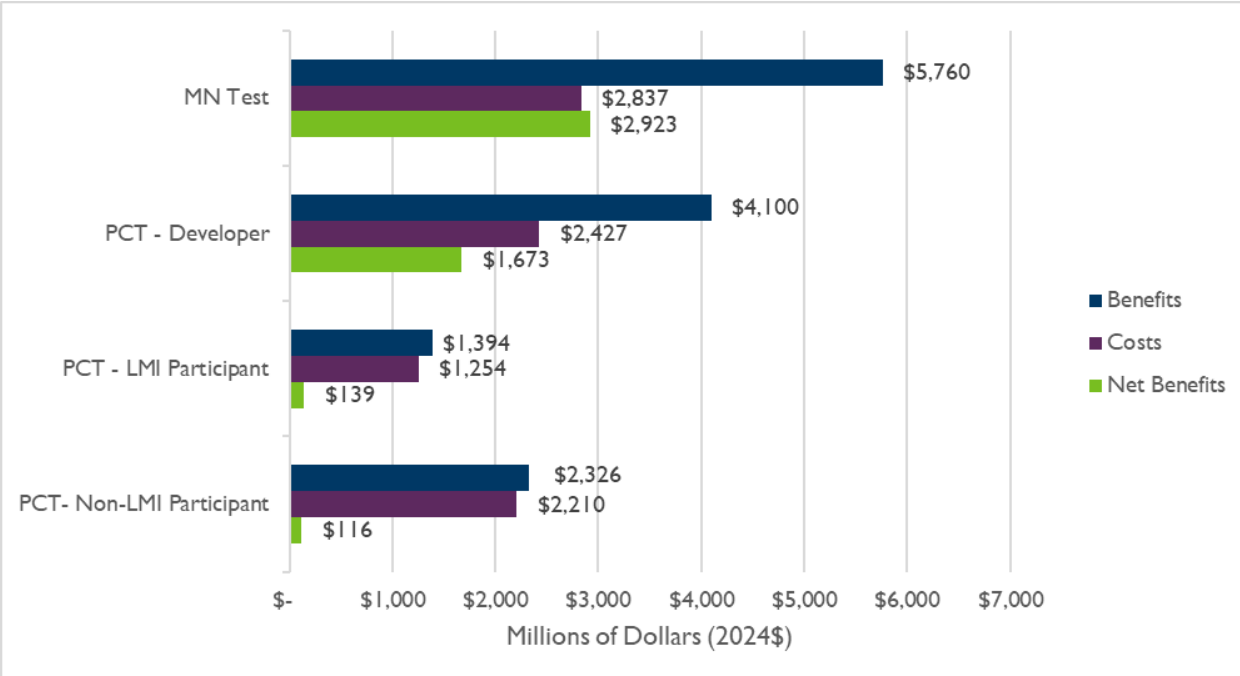
The 2023 amendments to § 216B.1641 establishing the LMI-Accessible CSG Program included the requirement for an “analysis of the cost to ratepayers of operating” the CSG program and a “comparison” with the costs of other potential options for encouraging the expansion of solar generation in Minnesota. Consistent with these sections of the enabling legislation, the report authors conducted a benefit-cost analysis (BCA) to estimate the expected impacts on ratepayers and society resulting from the LMI-Accessible CSG Program. The analysis does not include impacts from the Legacy CSG program, which accelerated the installation of solar in Minnesota through 2023.

BCA is used to quantitatively compare benefits to costs. These analyses are most useful in comparing alternative program structures, which may present equivalent benefits at lower costs. The report authors assessed the cost effectiveness of the CSG program using four cost tests: a modified Minnesota Test and three Participant Cost Tests: for developers, LMI subscribers, and non-LMI subscribers.[39] Each cost test reflects a different perspective and accounts for different benefits and costs; the result of each cost test utilized within the BCA is a distinct benefit-cost ratio (BCR). A BCR exceeding 1.0 indicates that program benefits exceed program costs for that cost test. BCA methodology is explained in more detail in Section 4.1, *Background on Community Solar Garden Program and Cost effectiveness*.

The results of these analyses are shown below in Figure 1. These results are sensitive to modeling assumptions and forecasts, which are discussed in the respective methodology sections and the sensitivity and alternatives analysis.

[39] The category of “developer” is broad and encompasses multiple parties and firms that may be engaged in the installation and operation and maintenance of community solar gardens, including financiers, EPC contractors, landholders, subscription managers, and others in addition to developers. For simplicity, however, the term “developer” is used throughout this report.

Figure 1: Summary of cost-effectiveness test results (millions of dollars, 2024$)



This figure displays the results of the Minnesota Test and the Participant Cost Test (PCT) from the perspective of the CSG developers, LMI participants (i.e., subscribers), and non-LMI participants. Costs and benefits are shown in millions of dollars. Notably, each test demonstrates positive net benefits, indicating the general cost effectiveness of the CSG program (i.e., benefits exceed costs). However, while both participants and developers experience net benefits, the developer net benefits far exceed the participating LMI and non-LMI net benefits, indicating that developers are the participant group most benefiting from the program.

Overview of Rate, Bill, and Participation Impacts Analysis Results

The report authors assessed the impacts of the CSG program on the rates and bills of different customer groups by conducting a rate, bill, and participation impacts analysis (RBPIA). Details on this analytical approach are provided in Section 4.1, *Background on Community Solar Garden Program and Cost effectiveness*. A summary of the RBPIA results is shown in Table 15 for low-income (LI), moderate-income (MI), high-income (HI) subscribing, and non-subscribing customers. The table displays both the impact on rates (cost of electricity per kWh) and the impact on monthly electricity bills in the years 2030, 2040, and 2050.

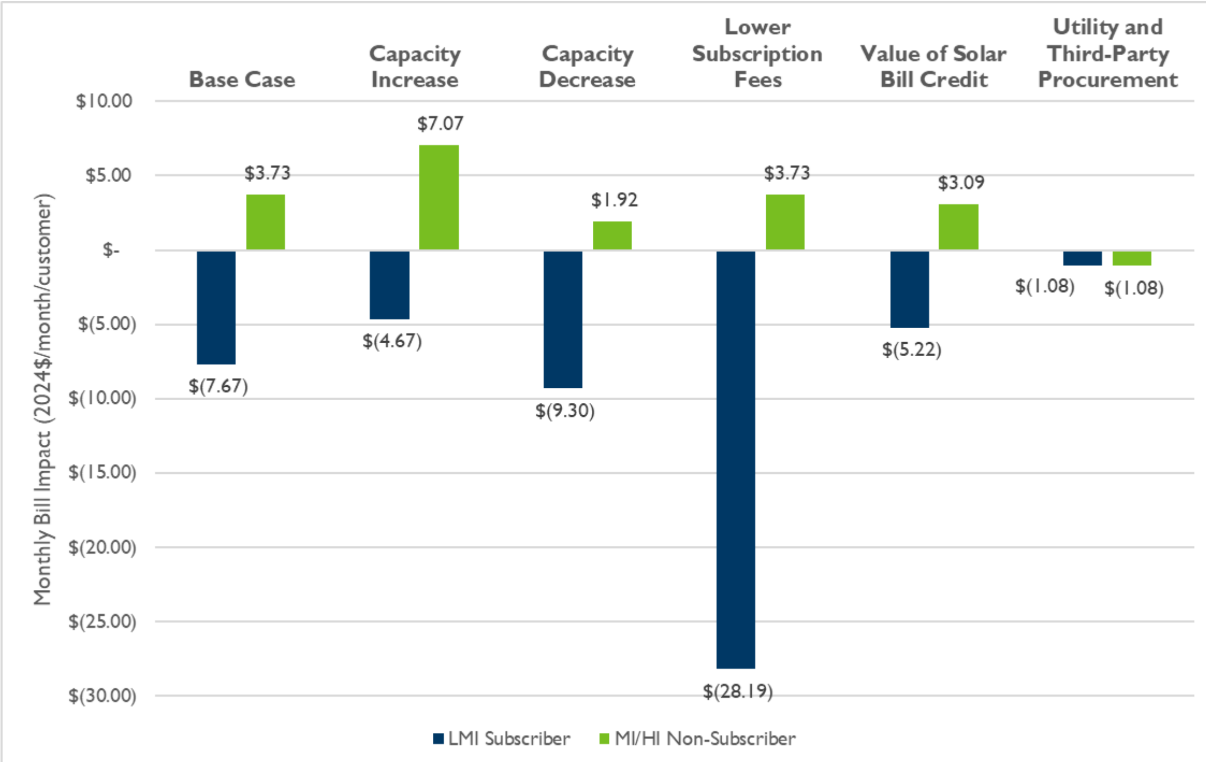
Table 15: Rate and bill impacts for CSG subscribers and non-subscribers

	Rate Impact (2024$/kWh)			Bill Impact (2024$/month)		
Customer Group	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
LI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
MI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
HI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (2.83)	$ (1.97)	$ (3.56)
Non-Subscribing LI Customer	$ (0.0016)	$ (0.0026)	$ (0.0018)	$ (1.06)	$ (1.96)	$ (1.51)
Non-Subscribing MI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Non-Subscribing HI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Small Commercial Subscriber	$ 0.0016	$ 0.0023	$ 0.0014	$ (17.82)	$ (18.94)	$ (21.54)
Non-Subscribing Small Commercial Customer	$ 0.0016	$ 0.0023	$ 0.0014	$ 1.33	$ 2.16	$ 1.46

The report authors find that by 2040, LI and MI subscribers will experience bill savings of about $7.67 per month or about $92.00 per year, representing a 7.6 percent decrease relative to their bill absent the program. By 2040, non-subscribing MI and HI customers experience bill increases of up to about $3.73 per month or about $45.00 per year, representing a 3.2 percent bill increase. Non-participating LI customers are excluded from paying the above-market costs of the program through the fuel surcharge, per the CSG statute, and thus enjoy some of the program's benefits without having to pay for the above-market costs of the program.

In addition to evaluating the current CSG program, this analysis also examined four alternatives: 1) a modification to the existing program with a lower CSG subscription fee; 2) modifications to the existing program with lower or higher annual installed CSG capacity limits; 3) a modification to the existing program with CSG bill credits based on VOS; and 4) an alternative solar procurement mechanism that would procure distributed solar at cost, including sufficient profit for solar developers (referred to as utility and third-party procurement). Figure 2 describes the monthly bill impacts of the current program and of each of the alternatives. Each bill impact is relative to no program being in place, discussed further in Section 4.1*, Background on Community Solar Garden Program and Cost effectiveness*.

Figure 2: Monthly bill impact in 2040 – base case and alternatives (2024$ per month)



This figure compares the monthly bill impacts in 2040 of the base case (i.e., the LMI-Accessible CSG Program without modifications) to four alternative program designs. Bill impacts are shown for LMI subscribers and non-LMI non-subscribers. A positive bill impact indicates an increase in monthly electricity bills relative to customer bills without the CSG program, while a negative bill impact indicates a decrease.

In the base case, an average LMI subscriber would save $7.67 per month by subscribing, while a medium- or high-income non-subscriber would have to pay an additional $3.73 per month relative to no program implementation. In the lower subscription fee alternative, the bill credit remains the same, so subscribers have substantially lower bills. The utility and third-party procurement alternative is the only alternative in which both subscribers and non-subscribers would see bill reductions. This is because the avoided costs of solar are greater than the cost paid by ratepayers. Under this alternative, there are no subscribers, and all ratepayers benefit from the increased solar, so the subscribers and non-subscribers experience the same bill impacts.

The consideration of alternatives in this analysis highlights the significant impact that subscription fees have on subscribers (diminishing the benefits of participation) and the significant savings that might be experienced by non-subscribers if the utility and third-party procurement alternatives were to be put in place.

The report authors' review of CSG program parameters and alternatives leads to the following findings and recommendations:

- LMI subscribers would experience higher bill savings if they did not have to pay the above-market CSG program costs through the fuel surcharge. In its current form, the CSG statute only protects non-participating LI customers from paying the above-market costs of this program.

Extending this protection to LMI subscribers or low-income customers alone would increase benefits to this key constituency and result in only a minor cost increase for non-participants. This provision of the law should be modified.

- The CSG program structure results in bill increases for medium- and high-income residential non-subscribers by 2030, which will continue to grow over time with the total installed capacity of community solar under the CSG program. On the other hand, the program is expected to support significant solar deployment and provide meaningful benefits to LMI subscribers. The costs and benefits of the program must be evaluated and weighed as the Minnesota electric sector progresses toward net-zero emissions by 2040.
- CSG subscription fees (developer revenues) are based on retail rates and play a critical role in determining the level of benefits experienced by subscribers. However, solar costs have no direct relationship to retail rates. The report authors, therefore, recommend the following:
    - Minnesota should continue to explore structures to promote utility and third-party procurement of distributed generation, as addressed in Docket No. E-002/CI-23-403, since these alternatives may provide similar benefits to the CSG program at a lower cost.
    - Commerce should prioritize CSG applications with the lowest subscription fees, which could be accomplished, for example, by making subscription fees a component of the scoring criteria in a competitive project selection process. The level of subscription fees has a large impact on the financial benefits realized by subscribers. Favoring lower-fee developers in allocating program capacity is consistent with the evaluation criteria provided in the 2023 amendments to § 216B.1641.
    - Prospective CSG subscribers would benefit from greater transparency. Commerce should consider publishing subscription fees for existing projects in a single place and in an easily accessible format (e.g., a web page) to encourage greater competition and transparency in the market.

Overall, the analysis finds that the CSG program will result in continued significant growth in the scale of solar in Minnesota, resulting in environmental benefits and financial benefits to CSG subscribers. However, the CSG program also creates rate and bill increases for non-subscribing ratepayers. The upward cost pressure can be mitigated through the use of alternative program structures or alternative procurement mechanisms, though these alternatives also present tradeoffs (such as not providing direct benefits in the form of bill credits to subscribers). Selecting the right mechanism or combination of mechanisms to deploy distributed solar in Minnesota will require balancing competing policy goals.

4.1 Background on Community Solar Garden Program and Cost - Effectiveness

This section provides key context for the analysis of CSG program costs and benefits analysis. The discussion in this section covers the statutory background and relevant history of the Legacy CSG program, the methods utilized to evaluate cost effectiveness, and important limitations to the report authors' analyses.

Benefit-Cost Analysis of LMI-Accessible CSG Program: Rationale and Methods

The Laws of Minnesota 2023, Chapter 60, Article 12, Section 73, which provide the parameters for this study, require that the study provide "[a]n analysis of the cost to ratepayers of operating the community solar garden program and a comparison with the cost to ratepayers of other potential options for encouraging adoption of solar electricity generation in this state." The structure and rules regarding the LMI-Accessible CSG Program are defined in Minnesota Statutes §216B.1641. The report authors carefully considered the context for this study, including a review of the responses to the Request for Information (RFI) issued by Commerce in April 2024, ultimately determining that both costs and benefits should be considered in evaluating the LMI-Accessible CSG Program. To this end, the report authors' analysis is an evaluation of the *net* costs of the LMI-Accessible CSG Program. However, since this evaluation considered costs and benefits as separate value streams, it is also possible to view LMI-Accessible CSG Program costs in isolation.

There are sound reasons to consider both the costs and the benefits of the LMI-Accessible CSG Program. First, considering only costs will yield a one-sided perspective that is inconsistent with standard evaluation practices; utilities and regulators typically account for both the costs and benefits of investments and programs to produce a balanced view that supports the best use of ratepayer funds. Evaluating both the costs and benefits of the LMI-Accessible CSG Program supports balanced decision-making about how best to procure solar and benefit LMI customers in Minnesota. More fundamentally, there is no coherent way to consider the costs to ratepayers of the LMI-Accessible CSG Program, pursuant to the statutory requirement, without considering any savings (avoided costs). The report authors' approach accounts for these avoided costs to ensure that the projections of rate and bill impacts are accurate.

The report authors conducted two separate but related analyses of the costs and benefits of the LMI-Accessible CSG Program—a BCA and an RBPIA. These methods are described generally below, while detailed methodologies for these approaches are presented in below0. The report authors caution that while these two analyses produce use results that can inform refinements to the existing program to maximize benefits to both participants and non-participants, there is also inherent uncertainty in these results. The report authors explore this uncertainty by examining sensitivities which estimate the impact on modeling results of changes to key assumptions. See Section 4.5, *Sensitivity and Alternatives Analyses*.

Overview of Methodology for Benefit-Cost Analysis

BCAs are a structured approach to assessing the cost effectiveness of an investment, program, or other intervention. For this study, BCA was utilized to assess the cost effectiveness of the LMI-Accessible CSG Program and other modifications to the CSG program or alternatives to procure distributed solar energy. Methods and results are presented in Section 4.5, *Sensitivity and Alternatives Analyses*0.

BCA is a fundamentally comparative effort, with the investment, program, or other intervention under consideration evaluated by comparing it against a counterfactual, which is the set of circumstances (or "state of the world") that would otherwise prevail if the investment, program, or other intervention were not pursued. In this case, the counterfactual is a scenario without the LMI-Accessible CSG Program, holding all else equal. This counterfactual does not represent a scenario that is likely to prevail under current conditions, given that the LMI-Accessible CSG Program is mandated by statute, but it is an analytical necessity to postulate such an alternative. It is important to note that if the CSG program were to be modified, Minnesota might need to implement other measures to procure renewable generation to meet its climate goals, and those replacement programs would have their own impact on the state's generation mix and utility costs. It is not clear how these many possibilities could be distilled into a single counterfactual. Therefore, assessing the program against a scenario under which it does not exist while keeping all else constant is the best method to isolate the benefits and costs of the program, which can then be compared to alternative procurement mechanisms by comparing the respective benefit-cost analyses and benefit-cost ratios.

If the BCA finds that benefits exceed costs for the investment, program, or other intervention under study, then this investment, program, or other intervention may be deemed cost effective. The ratio of benefits to costs is termed the *benefit-cost ratio (BCR)*, while the difference between benefits and costs is termed the *net benefits* or *net costs*. For example, a program with a BCR of 1.0 produces equal benefits and costs, while a BCR of 2.0 indicates that the hypothetical program generates twice the amount of benefits compared to the costs.

In narrow, quantitative terms, any cost-effective investment should yield a BCR exceeding 1.0 and should yield net benefits of some value greater than zero. However, as discussed earlier0, such results from a BCA are not dispositive; the question of which investments, programs, or interventions should be selected is usually more nuanced and requires more than just a cursory look at the BCR and net benefits to answer. Just because a program is cost effective does not mean it is necessarily the best or most appropriate measure to implement. Conversely, a program that is not found to be cost effective through BCA may still be worthwhile if it helps to achieve certain policy goals.

Overview of Methodology for Rate, Bill, and Participation Impacts Analysis

While the BCA produces estimates of the net costs or net benefits of the LMI-Accessible CSG Program, it does not address impacts on the rates and bills of CSG subscribers and non-subscribing customers. The RBPIA provides a key view of the effects of the LMI-Accessible CSG Program on different constituencies. While some cross-subsidization of subscribers by non-subscribers may be acceptable for the new LMI-Accessible CSG Program, the RBPIA indicates how much of an incremental cost the program will place on non-subscribers and can help policymakers and other key stakeholders evaluate whether the scale of incremental costs is justified by the benefits. RBPIA methods and results are presented in Section 4.4, *Rate, Bill, and Participation Impacts Analysis Results*0.

Cost Effectiveness and Rate and Bill Impacts of the Legacy CSG Program

The costs of community solar and the impacts of these costs on ratepayers have been an issue since the inception of the Legacy CSG program in 2014. Though the structure of these programs and the associated flows of benefits and costs are complex, it is the bill credit rate for CSG subscribers that is the key determinant of whether the program raises rates and bills for non-participating customers. The bill credit rate represents the cost of CSG energy to the utility system. Should this rate be less than the value provided by CSGs to the grid, then the net effect of CSGs would be a reduction in total system costs, which would be expected to eventually result in a decline in rates and bills for both subscribers and non-subscribers.

From the CSG program inception to the present, the bill credit rate has exceeded the VOS from these facilities.[40] When the CSG program was first instituted, the Commission articulated a preference that the bill credit value of the CSG subscribers be set at the VOS. Commerce finalized its VOS methodology in 2014, and Xcel filed tariffs in accordance with this methodology. The aim of pegging the bill credit rate to the VOS is fairness, to avoid or minimize cross-subsidization, but in practice, other considerations meant that the actual bill credit value provided to subscribing customers has always exceeded the VOS. Similarly, the calculation of CSG net costs—for recovery through the fuel adjustment rider—has never utilized the VOS to determine the value provided by these facilities to the wider grid. In contrast to setting the bill crediting rate, however, the value of energy from CSGs for net cost calculations has been consistently established at a level *below* the VOS.

From 2014 through 2016, CSG facility subscribers received bill credits that were valued at the Applicable Retail Rate (ARR). While the Commission acknowledged that the ARR did not actually reflect the value provided by these facilities, the Commission found that the more generous compensation level provided by the ARR was needed to make participation in the CSG program financially viable for solar developers.[41] From 2017 to 2023, when the Legacy program was closed, bill credits for subscribers to new CSG facilities were set equal to the given year's VOS rate, with updated VOS studies filed by Xcel each year. Also, subscribers to facilities with vintages prior to 2017 still receive credits equal to the ARR.[42] However, the Commission elected to include additional credit value ("adder") to supplement the VOS rate out of a view of the continuing need for additional financial inducement to bring CSG projects to market.[43]

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[40] Here, and throughout the report, the value of solar is defined as the sum of the avoided costs determined by the Value of Solar.

[41] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Approving Solar-Garden Plan with Modifications (September 17, 2014).

[42] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Approving Value-Of-Solar Rate for Xcel's Solar-Garden Program, Clarifying Program Parameters, and Requiring Further Filings (September 6, 2016).

[43] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Adopting Adder and Setting Reporting Requirements (November 16, 2018).

Since bill credits were consistently valued above the VOS for subscribers over the approximate ten-year duration of Legacy CSG, the aggregate impact of the Legacy program was a bill *increase* for all customers. For residential customers, this increase was estimated at $44 dollars per year by 2022.[44] With the Commission's May 2024 Order in Docket No. E-002/M-13-867, bill crediting for the older Legacy facilities was transitioned from an ARR-based scheme to a VOS-based approach, consistent with the method for crediting utilized by the later Legacy facilities.[45] It is important to recognize that the scale of the bill increase associated with the Legacy program is a reflection of the large scale of this program, which was the principal driver of growth in solar capacity in Minnesota over its approximate ten-year tenure and which resulted in a significant overall increase in installed solar capacity in the state. Moreover, the bill increase associated with the Legacy program is but one indicator of its impacts; the estimated bill impact does not account for many of the benefits of the Legacy program that flowed to participants and to the wider society.

Balancing Cost effective ness and Other Considerations in CSG Program Design

As discussed in the preceding sections, BCA results should not be used as the lone decision-making criteria when evaluating programs and deciding on potential changes. This section presents certain methodological limitations of BCA that point to the need for holistic decision-making.

Non-Quantified Benefits

While qualitative impacts may be considered on an ancillary basis as part of an evaluation of costs and benefits, the ultimate BCA results and RBPIA results reflect only those effects that can be quantified and monetized. There are many potentially relevant impacts associated with the CSG program (especially benefits) that may be difficult to account for in the context of the BCA. The responses to Commerce's RFI in advance of its commissioning of the present study illustrate this point.

Distributional Considerations

In the case of the current LMI-Accessible CSG Program, distributional considerations are critical in the overall program evaluation. Because CSG subscribers may receive bill credits in excess of the value of the energy procured by Xcel from the CSG facilities, there is a net cost transfer from subscribing customers to non-subscribing customers. Regardless of the results of the BCA and RBPIA, neither analysis can provide perspective on the merits of such a cost transfer.

Another key distributional question not resolvable by the BCA or RBPIA is the apportionment of net program benefits between CSG developers and CSG subscribers. Under the current program design, a large share of these program benefits is likely to be retained by the developers rather than by CSG

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[44] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Approving Community Solar Garden Program Rate-Transition Proposal with Modifications, at 24 (May 30, 2024).

[45] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Approving Community Solar Garden Program Rate-Transition Proposal with Modifications (May 30, 2024).

subscribers. While these benefits may be an artifact of the bill credit scheme established by statute, there is no BCA or RBPIA result that could be dispositive on the question of *how* these benefits should be split.

Benefit-Cost Analysis and Policy Decisions

A final methodological limitation is an overarching one: a BCA cannot dictate policy changes. While the BCA and the RBPIA provide useful indications of cost effectiveness, rate impacts, and cost-shifting, neither of these analytical approaches can indicate whether the LMI-Accessible CSG Program is the *best* approach to making solar accessible to LMI customers.

4.2 Methodology for Benefit-Cost Analysis

This section begins with an overview of the key structural features of the LMI-Accessible CSG Program that informs the modeling of the LMI-Accessible CSG Program cost effectiveness and then presents the methods and results of the BCA undertaken by the report authors.

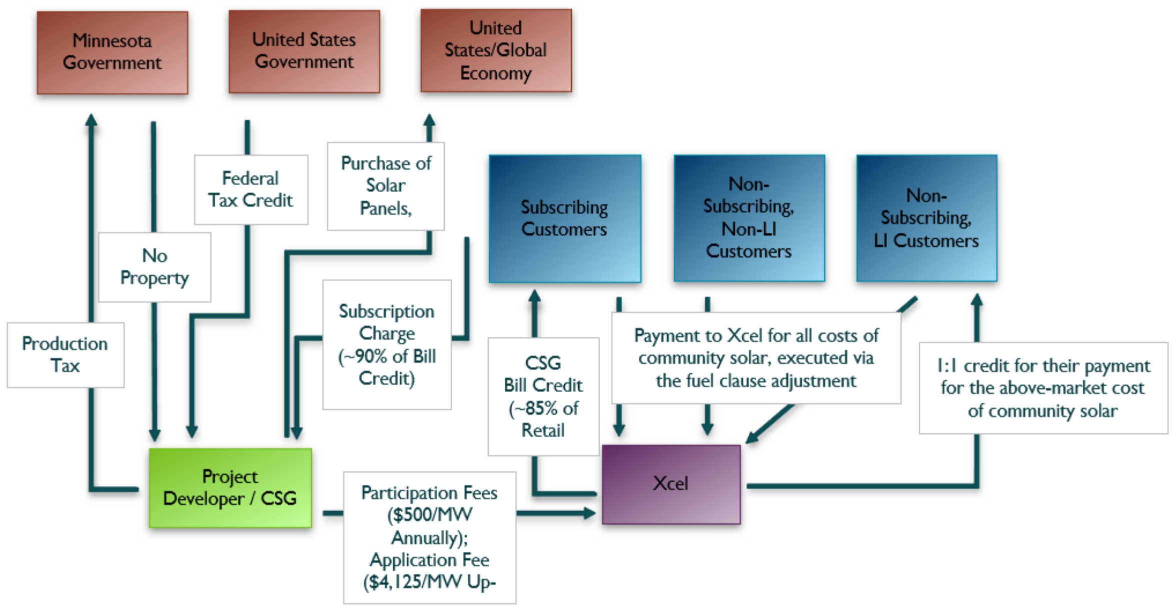
Key Modeled Features of LMI-Accessible CSG Program Structure

There are multiple structural aspects of the LMI-Accessible CSG Program that affect the modeling of its cost effectiveness and associated rate and bill impacts. The two diagrams in this section distill the program structure into a comprehensible visual form. Figure 3 presents the key financial transfers associated with the program, while Figure 3 presents the key benefits produced by the program.

Financial Transfers Associated with LMI-Accessible CSG Program

There are a variety of financial transfers that occur because of the statutorily prescribed program structure. Figure 3 illustrates these transfers. An explanation of this diagram follows.

Figure 3: Diagram of financial transactions associated with LMI-Accessible CSG program



Lines indicate the flow of dollars.

A key customer benefit of the LMI-Accessible CSG Program is the bill credit, which is provided to CSG subscribers. To receive this benefit, subscribers must pay a subscription charge to the project developer or owner of the CSG. Xcel, in turn, must purchase the solar energy created by the CSGs at the bill credit rate (i.e., by issuing bill credits to subscribing customers). Subscribing customers then receive a bill reduction via the bill credit. These costs are covered by ratepayers (shown as a set of arrows from each of the three ratepayer groups paying the cost of the community solar program, which is implemented via the fuel clause adjustment mechanism), except that non-participating LI customers are shielded from paying the above-market costs of the program.

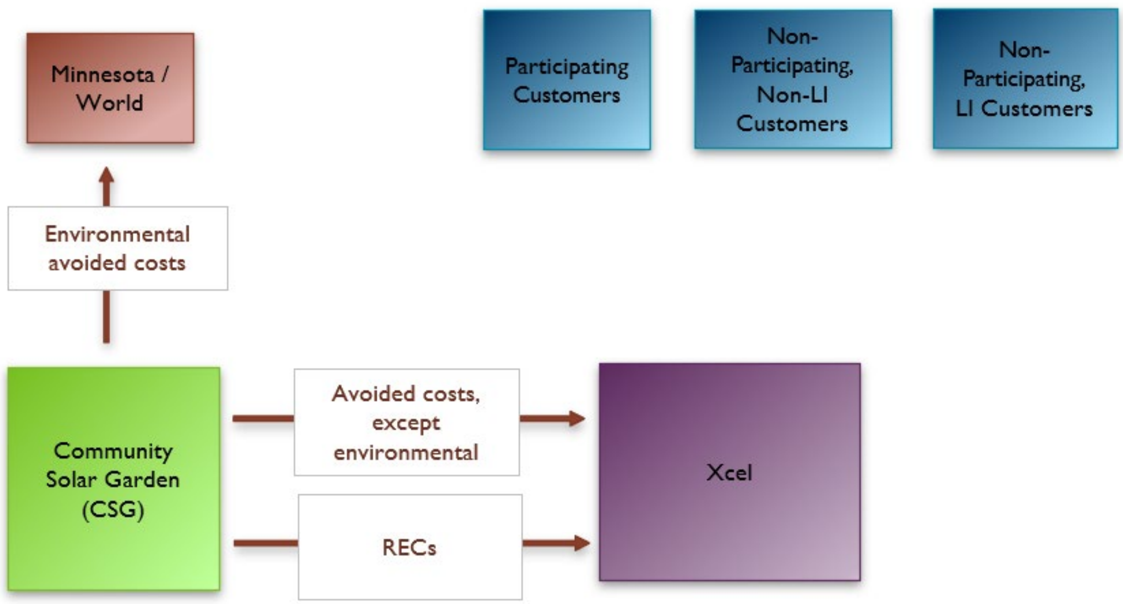
The CSG facility developers must pay Xcel an annual participation fee as well as an application fee to cover the administrative costs of implementing the program and installing necessary billing software. The project developers also must cover the basic cost of purchasing and installing the solar facility and any operating and maintenance expenses. These payments from developers are diagrammed as flowing to the broader United States economy and to the global economy.

Finally, project developers receive two tax incentives: the federal tax credit implemented via the investment tax credit, as well as a Minnesota-specific tax “exchange.” Within the Minnesota tax exchange, CSG developers of facilities over one MW do not need to pay property taxes but must instead pay a production tax for each kWh produced by the CSG facility.

Benefits and Costs of LMI-Accessible CSG Program

The production of electricity by CSGs, which is purchased by Xcel, produces both financial and non-monetary benefits. Figure 4 illustrates the flow of quantified benefits that are produced by CSGs. Notably, since the CSGs only interact with Xcel and not directly with participating customers, their benefits first accrue to Xcel and then flow through to ratepayers.

Figure 4: Diagram of quantified benefit transfers



Lines indicate the flow of non-monetary-transaction benefits.

Table 16 provides a detailed inventory of the benefits and costs associated with CSG facilities. These facilities are associated with a range of benefits and costs, which accrue variously to participants, the utility system, and society more broadly. In the following section, the cost tests that determine *which* costs and benefits should be included in the BCA are described in detail.[46]

Table 16: Summary of benefits and costs of the CSG Program

Impacts	Definition
Utility System Impacts	
Avoided energy costs	Avoided fuel and operating costs (fixed and variable) associated with producing or procuring energy.
Avoided capacity costs	Avoided cost of building or procuring capacity to meet the peak demand of the generation system (generation capacity and reserve capacity).
Avoided environmental costs	The avoided cost, based on the federal social costs of carbon emissions and MN PUC established externality costs for emissions from other compounds.

[46] For more extensive definitions, and additional detail on methodologies and resources, see National Energy Screen Project, *Methods, Tools, and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis*, March 2022, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2022/03/NSPM_Methods-Tools-Resources.pdf.

Impacts	Definition
Avoided RPS compliance costs	The avoided cost of complying with a renewable portfolio standard (RPS) or similar policy such as clean energy standards (CES) or clean peak standards (CPS).
Market price effects/demand reduction induced price effects (DRIPE)	The price reduction effect in competitive wholesale electricity markets price impacts from reducing system demand or increasing low-cost supply.
Avoided transmission costs	The avoided (or increased) cost of upgrading the transmission system to safely and reliably transfer electricity between regions. This avoided cost applies if the DERs passively defer investments by reducing load during transmission peak periods or if the DER is strategically placed to avoid transmission investments and is operated for that purpose. Alternatively, DERs can increase costs on the transmission system by adding new load.
Avoided distribution costs	The avoided (or increased) cost of upgrading the distribution system (including substations) to transfer electricity in local electric grids. If peak demand exceeds the capacity of a circuit, it will require investments to increase distribution capacity to a level that preserves safety and reliability. Similar to transmission avoided costs, DERs can passively or actively reduce strain on the distribution system. Alternatively, DERs can increase costs by adding a new load.
REC revenue	Revenue from selling renewable energy certificates (RECs). RECs are credits designed to represent the clean energy attributes of renewable energy generation.
Participant Impacts	
Subscription fees	The fees paid by participants to developers subscribe to a share of the electricity generated by the CSG facility.
Participant bill credits	Credits participants receive on their electric bills as compensation for their share of the energy produced by the CSG facility.
Installation costs	The costs for developers to construct and install CSG facilities.
Tax credits	Federal and state tax credits available to developers for CSG projects.
Developer application and participation fees	Fees paid by developers to the utility to cover the costs of administering the CSG program.
Societal Impacts	

Impacts	Definition
Greenhouse gas (GHG) emissions impacts	The benefits associated with reducing GHG emissions because of DERs. GHGs are created during fossil fuel-based energy production, transmission, and distribution. DERs that produce clean energy can avoid GHG emissions from other sources. In the BCA, this impact represents the avoided societal cost of GHG emissions.
Other environmental impacts	The benefits associated with reducing other environmental impacts, such as reduction in criteria air pollutants, because of DERs.

Approach to Developing Inputs for Benefit-Cost Analysis

Value of Solar and Avoided Costs

The avoided cost values for utility system impacts considered in this analysis are based on the 2023 vintage VOS values.[47] However, the report authors updated the VOS calculation by using up-to-date treasury yields using data from St. Louis FRED.[48] The VOS values were incorporated into the model by determining the percentage share of each avoided cost component relative to the total VOS. This method was applied to the 2023 VOS vintage for each year from 2023 to 2047, which is the 25th and final year applicable to the 2023 VOS vintage.[49] The values for 2047 through 2064 were extrapolated using the mean annual nominal growth rate between 2023 and 2047 of 2.44 percent. The results of these adjustments are shown below in Table 17.

Table 17: Value of Solar parameters before and after adjustments

Avoided Cost	Unadjusted 2023 Value of Solar—Distributed photovoltaic (PV) Value—25-Year Levelized Value ($/kWh)	Report Authors Adjusted 2023 Value of Solar—Distributed PV Value—25-Year Levelized Value ($/kWh)	Report Authors Adjusted 2023 Value of Solar—Distributed PV Value—Year 2024 (2024$/kWh)
Avoided Fuel Cost	$0.0361	$0.0357	$0.0296
Avoided Plant O&M – Fixed	$0.0017	$0.0017	$0.0014

[47] Xcel Energy, *2023 VOS Calculation Community Solar Gardens Program*, Docket No. E-002/M-13-867, September 1, 2022, Attachment A, Tab Table Fig. ES-1.

[48] St. Louis Federal Reserve, Market Yield on U.S. Treasury Securities at 1-Year Constant Maturity, Quoted on an Investment Basis, https://fred.stlouisfed.org/series/DGS1.

[49] Xcel Energy, *2023 VOS Calculation Community Solar Gardens Program*, Docket No. E-002/M-13-867, September 1, 2022, Attachment A, Tab Table Fig. ES-1.and Fid. ES-2. See also Xcel Energy, *Minnesota Electric Rate Book*, Section No. 9, 1st Revised Sheet No. 64.104, August 28, 2023.

Avoided Cost	Unadjusted 2023 Value of Solar—Distributed photovoltaic (PV) Value—25-Year Levelized Value ($/kWh)	Report Authors Adjusted 2023 Value of Solar—Distributed PV Value—25-Year Levelized Value ($/kWh)	Report Authors Adjusted 2023 Value of Solar—Distributed PV Value—Year 2024 (2024$/kWh)
Avoided Plant O&M – Variable	$0.0015	$0.0015	$0.0013
Avoided Generation Capacity Cost	$0.0241	$0.0241	$0.0200
Avoided Reserve Capacity Cost	$0.0021	$0.0021	$0.0017
Avoided Transmission Capacity Cost	$0.0199	$0.0199	$0.0165
Avoided Distribution Capacity Cost	$0.0041	$0.0041	$0.0021
Avoided Environmental Cost	$0.0428	$0.0428	$0.0355
Total	*$0.1323*	*$0.1319*	*$0.1081*

Environmental Benefits

Consistent with the Commission's December 28, 2023 Order in Docket No. E-002/CI-23-335, the report authors assumed that Xcel Energy will retain the RECs generated by the CSG project under the new CSG program.[50] At the time of this Order, the RECs were worth between $0.00175/kWh and $0.0025/kWh.[51] The report authors used the midpoint estimate of this value as an estimate of the REC price and assumed that the REC price would increase at the rate of inflation going forward. Additionally, the following pollutants were covered by the avoided environmental costs from the 2023 VOS values: carbon dioxide (CO_2), fine particulate matter (PM 2.5), carbon monoxide (CO), nitrogen oxides (NOx), lead (Pb), and sulfur dioxide (SO_2).[52] The report authors assume that any avoided RPS costs are embedded within the environmental benefits from the VOS.

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[50] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 19-20. (December 28, 2023).

[51] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 19. (December 28, 2023).

[52] Xcel Energy, 2023 VOS Calculation Community Solar Gardens Program, Docket No. E-002/M-13-867, September 1, 2022, Attachment A, Tab Table 4.

Energy Data

Energy sales for the residential, commercial, and industrial classes for 2001 to 2022 come from EIA 861 data obtained via Catalyst Cooperative's Public Utility Data Liberation (PUDL) tool. [53] Data from 2023 comes directly from EIA.[54]

The report authors used a linear forecast of the historical sales data to estimate sales for each class for 2024.

Energy sales for each class at a rate of 2 percent per year according to the estimate provided by Xcel in its 2024 to 2040 Upper Midwest Resource Plan Non-Technical Summary.[55]

Per-Customer Energy Usage

The report authors estimated the number of customers and the average energy consumption per customer. The residential customer count was estimated using EIA 861 data. The average usage per residential customer was estimated by dividing the residential energy use by the total number of residential customers. For 2024, this was estimated as 626 kWh/month. This was assumed to be constant across each of the six subgroups.

The total number of residential customers was projected to grow at a rate estimated via the EIA AEO 2023 reference case estimate for household growth, or 0.78 percent per year. The average usage per customer grew at a rate of 1.01 percent, derived from the energy growth rate and customer growth rate.

For the small commercial customer cohort, the report authors modeled the average usage per customer for rate A10 Small General Service based on the FERC Form 1 filed by Xcel Energy MN, which was estimated as 795 kWh/month in 2024.[56] The total number of commercial customers was projected to grow at a rate of 0.91 percent per year, as estimated via the EIA AEO 2023 reference case estimate for total commercial floor space growth. The average usage per customer was estimated to grow at a rate of 1.08 percent, derived from the energy growth rate and customer growth rate.

Residential Customer Breakdown

The LMI-Accessible CSG Program legislation includes a definition of an LMI subscriber as "a household whose income is 150 percent or less of the area median household income."[57] Additionally, Commerce highlighted that a definition of a low-income household could be a household earning 80 percent or less

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[53] Catalyst Cooperative, EIA 861 Yearly Sales (state = MN, utility_id_eia = 13781), https://data.catalyst.coop/pudl/core_eia861__yearly_sales?utility_id_eia__exact=13781&state__exact=MN&_sort=report_date. The transportation class was excluded from the analysis to ease calculation and due to its small size.

[54] Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861 detailed data files, October 10, 2024, https://www.eia.gov/electricity/data/eia861/.

[55] Xcel Energy, *2024-2040 Upper Midwest Resource Plan*, Docket E-002/RP-24-67, February 1, 2024, Appendix Z: Non-Technical Summary, p. 6.

[56] Federal Energy Regulatory Commission, Form 1 – Electric Utility Annual Report (Northern States Power Company (Minnesota) 2023 Q4 Filing), https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report.

[57] Minn. Stat. § 216B.1641, Subd. 2(d)(2).

of the area median household income. With this in mind, the report authors segmented the residential customer class into three income brackets: low income, medium income, and high income. These categories are defined as, respectively, less than 80 percent of AMI, between 80 percent and 150 percent of AMI, and above 150 percent of AMI. This income-based subdivision is applicable to subscribing customers and non-subscribing customers. Thus, there are six resulting subgroups of residential customers.

Each residential customer is a member of one of these six subgroups only: low-income subscribers, low-income non-subscribing customers, medium-income subscribers, medium-income non-subscribing customers, high-income subscribers, or high-income non-subscribing customers. The size of each of these customer groups was estimated by assigning a portion of the residential energy sales to each of the six groups. Then, under the assumption that each of the six subgroups has the same annual average energy usage, the number of customers in each of the six subgroups was estimated.

The report authors analyzed data from the Residential Energy Consumption Survey of 2020 and estimated that low-income, medium-income, and high-income customers used roughly the same amount of energy annually. Low-income customers used 92 percent of the residential average, medium-income customers used 106 percent of the residential average, and high-income customers used 114 percent of the residential average.

Residential customers can subscribe to the program either as an LMI customer or as a non-LMI residential customer. The report authors converted the subscribed capacity for LMI and HI residential customers to estimates of energy generation, with an assumption that each kWh of subscribed energy corresponds to a kWh of used energy for residential customers.[58]

LMI energy is split between low-income and moderate-income customers based on census information for Minnesota, which provides information on the number of families within income brackets between $10,000 and above $200,000. The estimated area median income (AMI) used was $108,215, reflecting the estimated family median income. The report authors estimate that 37 percent of households statewide are low-income households with less than 80 percent AMI, which is $86,572; 35 percent of households statewide are medium-income households with between 80 percent AMI and 150 percent AMI, which is $162,323; and 28 percent of households statewide are high-income households with above 150 percent AMI.

The total energy for non-participating customers is the complement of the subscribed LMI and HI energy described above. The non-participating energy is split among LI and MI customers based on comparable census income information.

Each of the six residential customer subgroups changes in size over time as participation in the LMI-Accessible CSG Program increases.

[58] Minn. Stat. § 216B.1641, Subd. 1(b). Because the Community Solar Garden statute establishes that each subscription shall be sized, "when combined with other distributed generation serving the premises, no more than 120 percent of the average annual consumption of electricity by each subscriber." Minn. Stat. § 216B.1641, Subd. 1. With 120 percent of average annual consumption serving as the maximum amount of kWh used by a customer per subscribed kWh, the assumption that the average customer subscribes to 100 percent of their annual usage is reasonable.

Bill Credits to Subscribers

Under the LMI-Accessible CSG Program, subscribers are compensated for their share of the electricity produced by the CSG facility based on specified percentages of the average retail rate, as shown in Table 18 below and reflected in the report authors' modeling.[59] Commerce provided values for each bill credit in its [request for applications](#) for the LMI-Accessible CSG Program. The bill credits change over time comparably to the retail rate, which is a 0.15 percent reduction per year, after adjusting for inflation, derived from the average price to all users for the fuel electricity from the [2023 AEO Energy Outlook](#) reference case.

Table 18: CSG bill credit amount by subscriber type

Subscriber Type	Bill Credit Definition	Subscriber Bill Credit (2024$/kWh)
LMI Residential	Average retail rate for residential customers	$0.1489
Non-LMI Residential	85 percent average retail rate for residential customers	$0.1266
Master-Metered Affordable Housing	80 percent average retail rate for residential customers	$0.1191
Public Interest Subscribers (Small General)	75 percent average retail rate for customer's rate class	$0.1118 - $0.1128
Public Interest Subscribers (General Service)	100 percent average retail rate for customer's rate class	$0.0978
Commercial (Other)	90 percent average retail rate for customer's rate class	$0.0685 - $0.1053

For CSG facilities with at least 50 percent of total capacity subscribed to by LMI customers, there are also specific compensation requirements for backup subscribers. However, backup subscribers are not included in the model, given that they are only relevant under specific circumstances.

Subscription Fees Paid by Subscribers

Subdivision 10 of Minn. Stat. § 216B.1641 outlines subscriber protections. The subscription fee that LMI subscribers pay to the CSG developer is capped at 90 percent of the bill credit. The report authors reviewed a sample of responses from developers and concluded that it is appropriate to assume that LMI subscribers pay a subscription fee of 90 percent of the bill credit.[60] For non-LMI subscribers,

[59] Minn. Stat. § 216B.1641, Subd. 8(b)(1)-(8).

[60] "Request for Proposals," Minnesota Department of Commerce Business Regulation, June 2, 2024, https://mn.gov/commerce/business/rfp.jsp.

subscription fees may not exceed the value of the subscriber's bill credit.[61] However, the model assumes that the subscription fee is set at 95 percent of the bill credit for these customers, reflecting the assumption that modest bill savings would be necessary to entice participation. The amount of savings for non-LMI subscribers is also generally supported by the sample responses from developers.

Capacity Allocation

Subdivision 7 of Minnesota Statute § 216B.1641 defines the annual capacity limits and allocation among customer groups. Table 19 presents the capacity allocation in the model for each subscriber type, which is reflected in the report authors' modeling. The maximum capacity in the program increases by 100 MW per year from 2024 to 2026, 80 MW per year from 2027 to 2030, and 60 MW per year for each year thereafter.[62]

Within the capacity that is eligible for the program each year, 30 percent must be subscribed to by LMI subscribers, and 55 percent must be subscribed to by some combination of LMI subscribers, public interest subscribers, or an affordable housing provider.[63]

The percentage of subscribed capacity in the legacy program did not have enough residential subscriptions, let alone LMI residential subscriptions, to meet this component of the capacity requirements.[64] Thus, the projected capacity subscription for the LMI-Accessible CSG Program must be estimated anew and will be discrepant from historical subscription rates. Table 19 presents the capacity allocation in the model for each subscriber type. A variation of this assumption with more residential capacity allocation is explored in Section 4.5*, Sensitivity and Alternatives Analyses*.

Table 19: Capacity allocation by subscriber type

Subscriber Type	Capacity Allocation
LMI Residential	30%
Non-LMI Residential	5%
Master-Metered Affordable Housing	5%
Public Interest Subscribers (Small General)	Small General Service: 15% General Service Non-Demand: 20%
Public Interest Subscribers (General Service)	20%
Commercial (Other)	Small General Service: 0% General Service Non-Demand: 0%

[61] Minn. Stat. § 216B.1641, Subd. 10(b).

[62] Minn. Stat. § 216B.1641, Subd. 7(a)(1)-(3).

[63] Minn. Stat. § 216B.1641, Subd. 7(b)(6)(c)(1)-(2).

[64] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, at 28, Figure 4 (May 30, 2024). Only 16 percent of capacity is subscribed to by residential subscribers.

Subscriber Type	Capacity Allocation
	General Service Demand: 5%

The current application pool for the LMI-Accessible CSG Program has seen most of the capacity allocated to residential customers. While increased residential participation compared to the legacy program is expected due to the increase in bill credits, particularly for LMI subscribers, actual capacity allocations for residential customers for future CSG projects are still uncertain. The report authors' capacity allocation assumptions, therefore, contain more residential allocations than those in the legacy CSG program but less than those in the current application pool for the updated program. A variation of this assumption with more residential capacity allocation is explored in Section 4.5, *Sensitivity and Alternatives Analyses***Error! Reference source not found.**.

Capacity Factor

The capacity factor refers to the ratio of the energy produced by a generator (e.g., solar facility) over a certain period of time compared to the maximum possible energy it could produce if operating at full capacity continuously during that period. When converting from the capacity of installed solar to the annual energy produced by that capacity, the report authors used the PV Fleet Shape from the 2023 VOS.[65] The capacity factor is defined as the calculated annual energy production divided by the product of system capacity and the number of hours in a year. The capacity factor estimated for CSGs is 22 percent.

Capacity Degradation

The report authors assumed that solar facility capacity would degrade over time, making CSG facilities less efficient in generating power in every subsequent year. The report authors followed the 2023 Value of Solar Study and used a 0.5 percent per year degradation rate.[66]

Installation and Operation and Maintenance Costs

The report authors estimated the costs of CSG projects using a community solar model from the National Renewable Energy Laboratory (NREL), which includes both capital costs as well as operations and maintenance (O&M) costs. Capital costs include the costs of the solar system's components, installation, permitting and interconnection, logistics, subscriber acquisition, overhead labor, sales tax, and profit, totaling $1.88/W$_{DC}$.[67] O&M costs include preventative and corrective maintenance costs,

[65] Xcel Energy, *2023 VOS Calculation Community Solar Gardens Program*, Docket No. E-002/M-13-867, September 1, 2022, Attachment O.

[66] Xcel Energy, *2023 VOS Calculation Community Solar Gardens Program*, Docket No. E-002/M-13-867, September 1, 2022, Attachment A, Tab Table 3. Fixed Assumptions.

[67] Vignesh Ramasamy, Jarett Zuboy, Michael Woodhouse, Eric O'Shaughnessy, David Feldman, Jal Desai, Andy Walker, Robert Margolis, and Paul Basore, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, with Minimum Sustainable Price Analysis: Q1 2023,* p. 23-24*,* National Renewable Energy Laboratory, NREL/TP-7A40-87303, September 2023, https://www.nrel.gov/docs/fy23osti/87303.pdf. PV Only estimated modeled market price (MMP) converted from 2022 dollars to 2024 dollars.

insurance, property tax, land lease, and subscriber management costs, totaling \$43.27/kW_{DC}/year.[68] The representative system modeled by NREL is a 3 MW_{DC} fixed-tilt community solar system, providing per-unit costs that are "meant to be generally applicable to systems with PV sizes between about 1.5 and 6 MW_{DC}."[69] Individual CSG installations may have costs that differ from the estimates provided by NREL. In addition, the report authors used NREL's 2024 Annual Technology Baseline (ATB) data for commercial solar photovoltaics to project future capex and O&M costs. The report authors applied the growth rates from the NREL ATB to the NREL point-in-time estimates.

The estimates from NREL were also benchmarked against an alternative source for information on solar installation prices, namely Lawrence Berkeley National Lab's *Tracking the Sun* report. NREL's estimates are derived from a bottom-up approach of estimating the installation cost based on the cost of component parts and labor, while LBNL's estimate is a result of surveys of the total price of actual installations.[70] LBNL provides a comparable estimate of the installation costs of large non-residential systems over 1000 kW at \$1.74/W_{DC}, comparable to NREL's estimate of \$1.88/W_{DC} for a 3MW_{DC} fixed-tile community solar system.[71] Furthermore, LBNL provides evidence that non-residential installation costs within Minnesota are comparable to estimates for the entire United States.[72]

Federal and State Tax Incentives

The report authors included federal and state tax credits currently available to solar developers. At the federal level, solar projects can choose between an investment tax credit (ITC), which is applied to the upfront installation cost of the solar system, or a production tax credit (PTC), applied to the electricity generated by the solar system for the first 10 years of operation.[73] The report authors assumed that solar projects under the LMI-Accessible CSG Program will opt for the ITC, which is more favorable for projects with relatively higher capital costs.[74] Projects that begin construction by 2033 are eligible for a 30 percent ITC, which then phases down to 23 percent for projects that begin construction in 2034, 15 percent for projects that begin construction in 2035, and finally 0 percent in 2036 and after.

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[68] Ramasamy et al., p. 31, 33. PV Only estimated modeled market price (MMP) converted from 2022 dollars to 2024 dollars. The report authors assume in the model that the entity managing subscriptions and the entity installing solar are the same and are referred to as the developer. This may not reflect actual community solar inter-company arrangements; however, the costs for both groups are accounted for in NREL's cost estimates.

[69] Ramasamy et al., p. 23.

[70] NREL discusses the differences on pages 6-8 of their report and LBNL provides a comparison of the estimates on slide 32 of their report.

[71] Lawrence Berkeley National Laboratory, Tracking the Sun, p. 36, accessed October 29, 2024, https://emp.lbl.gov/tracking-the-sun.Converted from 2023 dollars to 2023 dollars.

[72] Lawrence Berkeley National Laboratory, Tracking the Sun, p. 37.

[73] US Department of Energy, Federal Solar Tax Credits for Businesses, https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses.

[74] ICF, Solar economics: The PTC vs. ITC decision, December 15, 2022, https://www.icf.com/insights/energy/solar-economics-ptc-vs-itc#:~:text=Solar%20developers%20now%20have%20an%20option%20to%20select,likely%20see%20more%20benefits%20from%20PTC%20than%20ITC.

Additionally, the ITC includes three bonuses for projects with certain characteristics: an Energy Community Bonus, a Domestic Content Bonus, and a Low-Income Communities Bonus.

To qualify for the Energy Community Bonus, which provides an additional 10 percent ITC to projects that begin construction by 2033, 7.5 percent in 2034, 5 percent in 2035, and 0 percent after, the project must be sited in an "energy community" as designated by the Department of Energy. These energy communities marginally overlap with Xcel's service territory.

The Domestic Content Bonus provides the same additional ITC as the Energy Community Bonus and requires a certain percentage of the facility's components to be produced in the US. The report authors were unable to ascertain the proportion of CSG projects expected to qualify for this bonus.

Finally, the Low-Income Communities Bonus provides an additional 10 percent ITC for projects that begin construction by 2033 if the project is located in a low-income community or on Indian land; or an additional 20 percent ITC for projects that begin construction by 2033 and are classified as a "qualified low-income residential building project" or a "qualified low-income economic project." A small number of CSG projects may qualify for the Low-Income Community Bonus, but the exact number could not be estimated.

Given the uncertainty around the possibility of CSG projects receiving each bonus, the report authors assume that each CSG project would receive an additional 10 percent credit to account for the impact of qualification for one of the bonuses. This would be phased out comparably to the Energy Community Bonus, where the credit would be 10 percent if construction begins by 2033, 7.5 percent if construction begins in 2034, 5 percent if construction begins in 2035, and 0 percent if construction begins in 2036 and after.

Another federal incentive is the Solar for All program. The United States Environmental Protection Agency recently announced that Minnesota would receive $62.4 million dollars under this program. This funding will be used to provide financial assistance, interconnection, and administration, among other programs. Minnesota Department of Commerce's Solar for All application states that 35 percent of the $100 million of Solar for All funding that was applied for would be used for community-owned community solar lending. The report authors did not include this Solar for All funding in the model but note that it may cause changes to subscription fees and installation costs for qualifying community-owned community solar facilities.

On the state level, solar projects larger than one MW in Minnesota are exempt from property taxes. Instead, these solar projects must pay a production tax of $1.20 per MWh of electricity generated.[75] To reflect this benefit, the property tax component of the operation and maintenance costs modeled by NREL were removed, and the cost of the alternative production tax was added.[76] The report authors' model did not account for potential funding from the Renewable Development Account, given that there is no certainty regarding the use of this funding for the LMI-Accessible CSG Program.

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[75] DSIRE, Wind and Solar-Electric (PV) Systems Exemption, NC Clean Energy Technology Center, October 9, 2024, https://programs.dsireusa.org/system/program/detail/151/wind-and-solar-electric-pv-systems-exemption.

[76] Ramasamy et al., p. 33.

Application Fees from Developers

The model included certain fees paid by developers to Xcel to cover the costs of the administrative changes and other ongoing implementation costs necessary for the new LMI-Accessible CSG Program. Specifically, CSG developers were charged a one-time fee for each application at a rate of $4,125 per MW as well as an annual fee of $500 per MW. The report authors modeled that the one-time fee would not be recovered in the years after $3.2 million was cumulatively recovered from the fee, reflecting the fact that this fee is meant to recover the costs of implementing consolidated billing and implementing the LMI-Accessible CSG statute.[77]

Inflation Assumptions

To reflect the impact of inflation, the report authors used the monthly historical consumer price index for all urban consumers from the Federal Reserve Bank of St. Louis.[78] Annual inflation data for 2024 was estimated as the average (arithmetic mean) monthly inflation rate for 2024 through September. Forecast inflation data came from the Federal Reserve Bank of Cleveland. The average of each year of expected inflation from 2024 through 2054 is 2.20 percent.

Scope of Modeling within Benefit -Cost Analysis

The model includes all CSG facilities installed under the LMI-Accessible CSG Program through 2040. The report authors chose 2040 as the end date for installations because this is the year by which the Minnesota net-zero requirement must be met.[79] Additionally, the report authors deemed 16 years of installations between 2024 and 2040 as a reasonable expected life for this program. Given that the solar installations are assumed to have a lifetime of 25 years, solar production from CSGs is projected to cease in 2064 in the model. Thus, the study period of the model is between 2024 and 2064.

The counterfactual for the analysis is that the LMI-Accessible CSG Program is not put in place. This allows for a clear comparison between the program as planned and potential alternatives.

4.3 Cost Test Approaches and Results

Modified Minnesota Test Approach and Results

This section and the following one describe the cost tests that were used in the report authors' evaluation of the LMI-Accessible CSG Program and alternatives and then provide results for each cost test. This section covers the modified Minnesota Test, which examines a broad scope of societal benefits versus the cost of solar procurement.

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[77] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, at 11-12 (May 30, 2024).

[78] Federal Reserve Bank of St. Louis, Federal Reserve Economic Data, Series CPIAUCSL, https://fred.stlouisfed.org.

[79] Minnesota Department of Commerce, "Governor Walz Signs Bill Moving Minnesota to 100 Percent Clean Energy by 2040," February 7, 2023, https://mn.gov/commerce/news/?id=17-563384.

The report authors note that BCA results are most informative when viewed in comparison to alternatives or modified CSG designs, which are explored later in this report. In other words, just because a program's benefits are greater than its costs do not guarantee that the program design is optimal for society and/or ratepayers. The question of optimality can only be approached by considering and comparing multiple program designs.

Modified Minnesota Test

In 2023, the Minnesota Public Utilities Commission (MPUC) adopted cost-effectiveness methodologies for energy efficiency programs, finding that the "Minnesota Test," which focuses on the benefits and costs to the utility system (i.e., ratepayers) and to society, should be adopted as the primary cost-effectiveness test. The report authors' analysis incorporates a modification to the Minnesota Test via the addition of participant costs and participant benefits, which are normally excluded from the Minnesota Test.[80] These additions were motivated by the recognition that the evaluation of cost effectiveness for the LMI-Accessible CSG Program differs from the evaluation of the cost effectiveness of energy efficiency, namely because results for the present analysis will only be meaningful if solar costs—technically a "participant cost" in this modified framework—can be compared with societal benefits.

The modified Minnesota Test is akin to a Societal Cost Test (which evaluates a broad scope of benefits that accrue to ratepayers, program participants, and society at large, including environmental, health impacts, and monetary utility system impacts as avoided costs). The total value of these benefits is compared with the costs incurred to provide them.[81]

The report authors utilized the modified version of the Minnesota Test as part of the CSG analysis and incorporated all relevant values that could be quantified with existing data—primarily data from the 2023 VOS. As a result of the modification to the Minnesota Test, the report authors also included distributed solar costs as well as federal and state tax benefits, which are considered to be participant costs and benefits, respectively.

The benefits and costs included in the modified Minnesota Test are presented below in Table 20.

Table 20: Benefits and costs included in the modified Minnesota Test

	Impact
Benefits	Value of RECs
	Avoided Fuel Cost
	Avoided Plant O&M – Fixed
	Avoided Plant O&M – Variable
	Avoided Generation – Capacity
	Avoided Reserve Capacity Cost

[80] Minnesota Department of Commerce, *In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Docket No. E,G999/CIP-23-46, Decision, at 91-93 (March 31, 2023).

[81] Minnesota Department of Commerce, *In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Docket No. E,G999/CIP-23-46, Decision, at 37-39 and 91-93 (March 31, 2023).

	Impact
	Avoided Transmission Capacity Cost
	Avoided Distribution Capacity Cost
	Avoided Environmental Cost
	Federal Tax Credit
	Property Tax Exemption
Costs	Annual Participation Fee
	Application Fee
	PV Installation Capital Costs
	PV Installation Operating and Maintenance Costs
	Production Tax

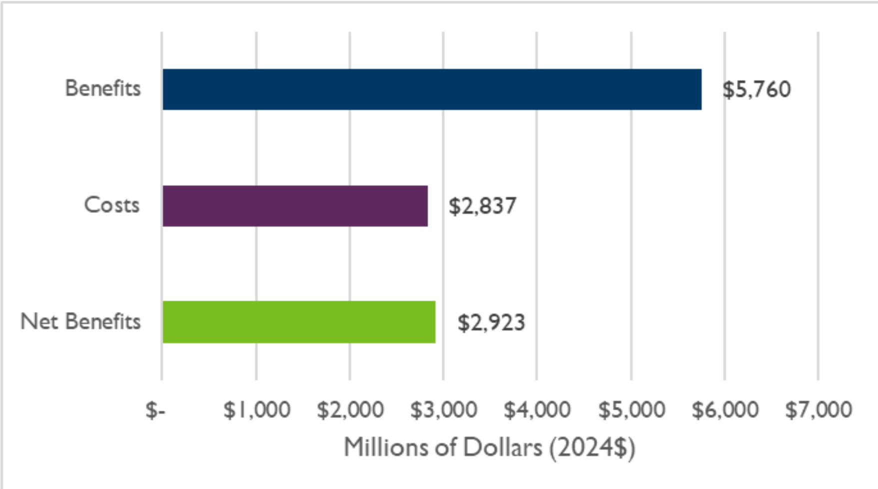
Through applying the modified Minnesota Test, the report authors compared the cost of community solar to the combined ratepayer and Minnesota benefits resulting from the LMI-Accessible CSG Program.

Benefit-Cost Analysis Results for the Modified Minnesota Test

Applying the modified Minnesota Test produces an estimate for the total benefits of the LMI-Accessible CSG Program to ratepayers and society that exceeds the total costs of procuring solar energy. The resulting BCR is 2.03. In other words, the benefits of the LMI-Accessible CSG Program are 2.03 times its costs. Net benefits equal a net present value of $2.5 billion over the study period. The costs in Figure 5 are the net present value of the costs included in Table 20, principally the community solar capital costs. The benefits in Figure 5 are the net present value of the benefits included in Table 20 and shown in Figure 6. The net present value is a method for accounting for the time value of money in a time series of financial transactions and presenting the result in present-day (2024) dollars. A nominal discount rate of 3.3 percent and an inflation rate of 2.2 percent were used to calculate the net present value.[82]

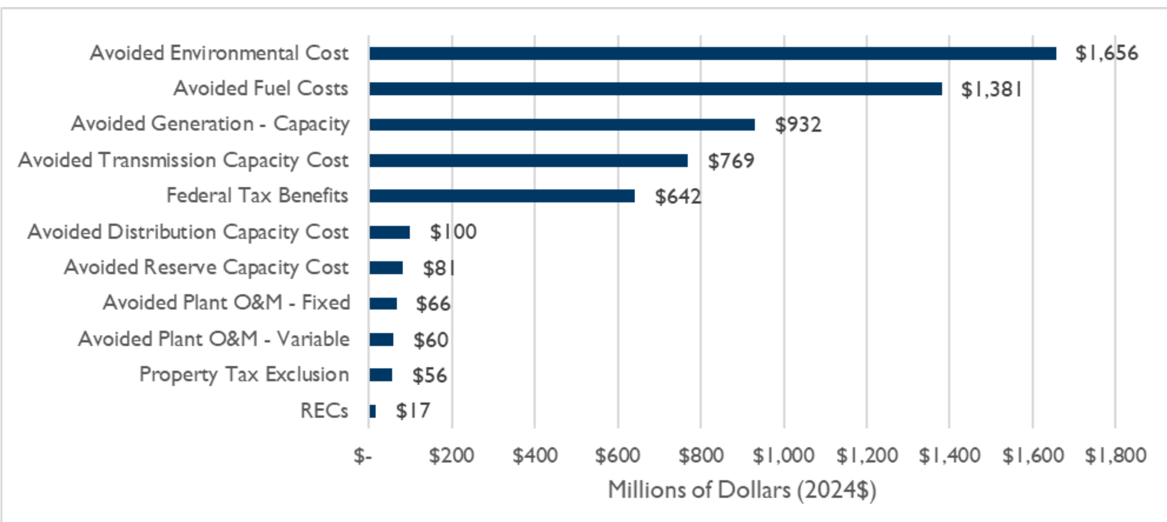
[82] Minnesota Department of Commerce, *In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Docket No. E,G999/CIP-23-46, Decision, at 97 (March 31, 2023).

Figure 5: Modified Minnesota Test results – net present value (millions of dollars 2024$)



This figure shows the net present value of the benefits, costs, and net benefits of the LMI-Accessible CSG Program under the modified Minnesota Test. The net benefits are calculated by subtracting the costs from the benefits.

Figure 6: Modified Minnesota Test benefits – net present value (millions of dollars 2024$)



This figure displays the net present value of each benefit type included in the modified Minnesota Test, including the avoided costs included in the Value of Solar Study, federal tax benefits, removal of property tax payments, and the value of RECs generated by the solar gardens.

Participant Cost Test s Approaches and Results

The report authors also conducted Participant Cost Tests to examine the benefits and costs of the LMI-Accessible CSG Program to different participant groups.

Participant Cost Tests

The Participant Cost Tests evaluated costs and benefits to three different participant groups: solar developers, LMI subscribers, and non-LMI subscribers. These analyses offer alternatives to the broader perspective provided by the modified Minnesota Test. There are two broad “participant” perspectives for LMI-Accessible CSG Programs: the perspective of CSG developers and the perspective of CSG subscribers. Developers incur upfront capital and ongoing O&M costs for solar installation and a tax on solar production; this is offset by revenues from CSG subscribers and tax credits from the federal government and state government (property taxes). CSG subscribers pay a subscription fee, which is offset by bill credits as established by law. Bill credit and subscription fee values differ for LMI and non-LMI subscribers, so these subscriber groups are examined separately. Benefits and costs included in the Participant Cost Tests are presented below in Tables 21 and 22.

Table 21: Benefits and costs included in the Participant Cost Tests for developers

	Impact
Benefits	Federal tax credits
	Property tax exemption
	Subscription revenues
Costs	Annual participation fee
	Application fee
	PV installation capital costs
	PV installation operating and maintenance expense costs
	Production tax

Table 22: Benefits and Costs Included in the Participant Cost Tests for LMI and non-LMI Subscribers

	Impact
Benefits	Bill credit
Costs	Subscription fee

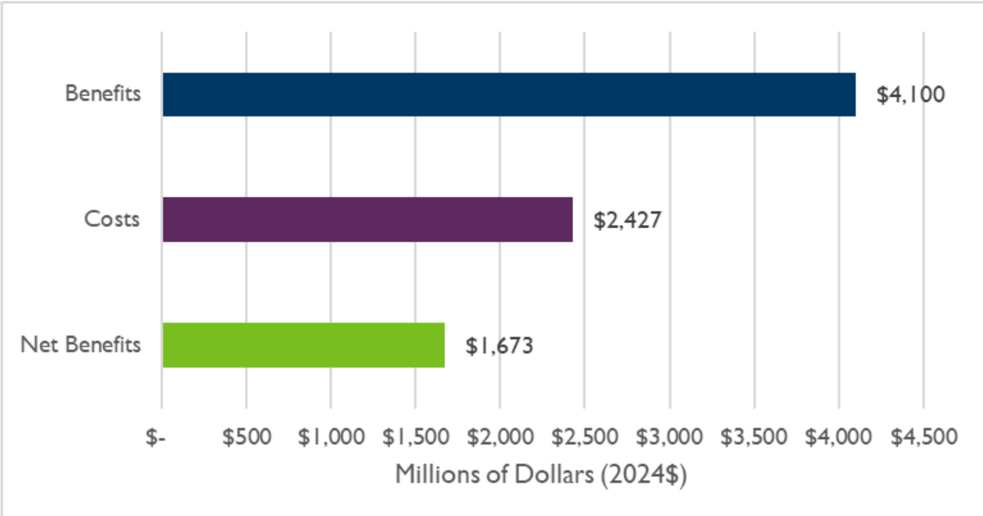
Benefit-Cost Analysis Results for the Participant Cost Tests

For developers, the monetary benefits of the program were found to be significantly greater than the costs.[83] As displayed in Figure 7, the net present value of the net benefits was $1.7 billion over the study period, and the test resulted in a benefit-cost ratio (BCR) of 1.69, meaning that developer benefits are estimated to be 69 percent greater than costs. A nominal discount rate of 5.4 percent and an inflation rate of 2.2 percent were used to calculate the net present value.[84]

[83] The category of “developer” is broad and encompasses multiple parties and firms that may be engaged in the installation and operation and maintenance of community solar gardens, including financiers, EPC contractors, landholders, subscription managers, and others in addition to developers. For simplicity, however, the term “developer” is used throughout this report.

[84] Minnesota Department of Commerce, *In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Docket No. E,G999/CIP-23-46, Decision, at 97 (March 31, 2023),

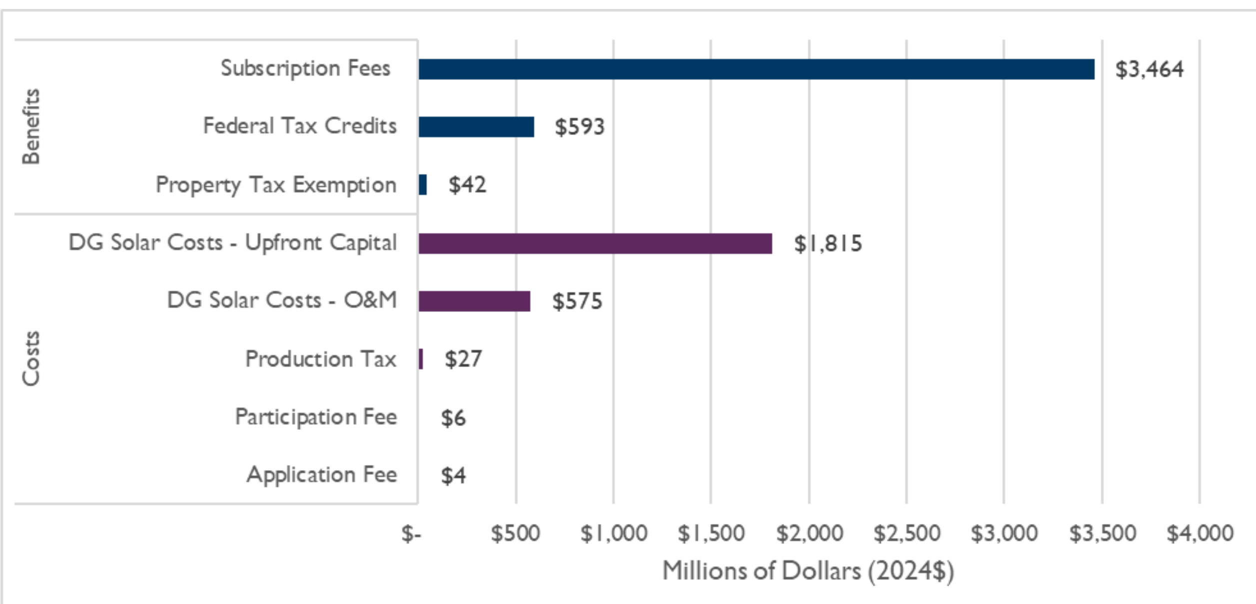
Figure 7: Participant Cost Test results: developer perspective – net present value (millions of dollars 2024$)



This figure shows the net present value of the benefits, costs, and net benefits of the LMI-Accessible CSG Program experienced by developers under the Participant Cost Test. Net benefits are calculated by subtracting the costs from the benefits.

Developer benefits are primarily comprised of the subscription fees received from subscribers, along with federal tax credits and the exemption from property taxes to a lesser extent. As displayed in Figure 8, costs consist primarily of CSG capital and O&M costs, including subscription acquisition and management costs, followed by production tax payments and utility administration costs (application and participation fees).

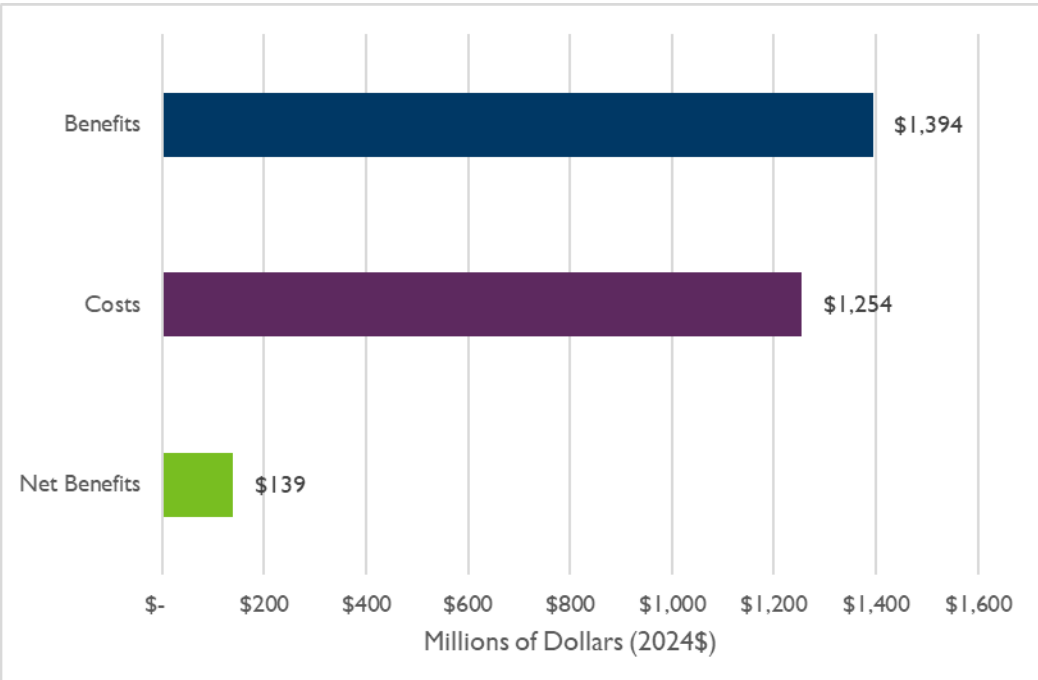
Figure 8: Developer Participant Cost Test cost and benefits – net present value (millions of dollars 2024$)



This figure displays the net present value of each benefit and cost type included in the Developer Participant Cost Test. This comparison provides the relative size of each cost and benefit type to contextualize why the developer *benefits are higher than developer costs—and demonstrates that this is primarily driven by revenues from subscription fees.*

For LMI subscribers, the monetary benefits of the program are estimated to be slightly greater than the costs. The net present value of the net benefits is $139 million over the study period, and the test results in a BCR of 1.11, meaning that benefits are estimated to be 11 percent greater than costs. As displayed in Figure 9, the benefits to LMI subscribers consist solely of bill credits from the program, while the costs are the subscription fees charged by developers.

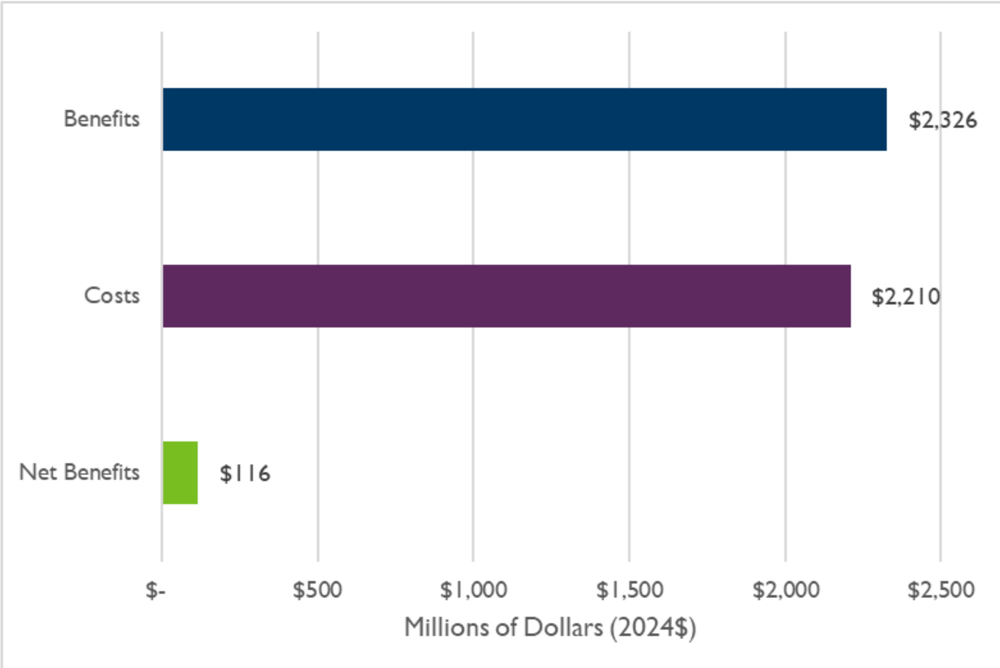
Figure 9: LMI Subscriber Participant Cost Test cost and benefits – net present value (millions of dollars 2024$)



This figure shows the net present value of the benefits, costs, and net benefits of the LMI-Accessible CSG Program experienced by LMI subscribers under the Participant Cost Test. Net benefits are calculated as the benefits minus the costs.

Similarly, for non-LMI customers, the monetary benefits of the program are estimated to be slightly greater than the costs. The net present value of the net benefits is $116 million over the study period, and the test results in a BCR of 1.05, meaning that benefits are estimated to be 5 percent greater than costs. As displayed in Figure 10, the benefits to LMI subscribers consist solely of bill credits from the program, while the costs are the subscription fees charged by developers.

Figure 10: Non-LMI Subscriber Participant Cost Test cost and benefits (millions of dollars 2024$)



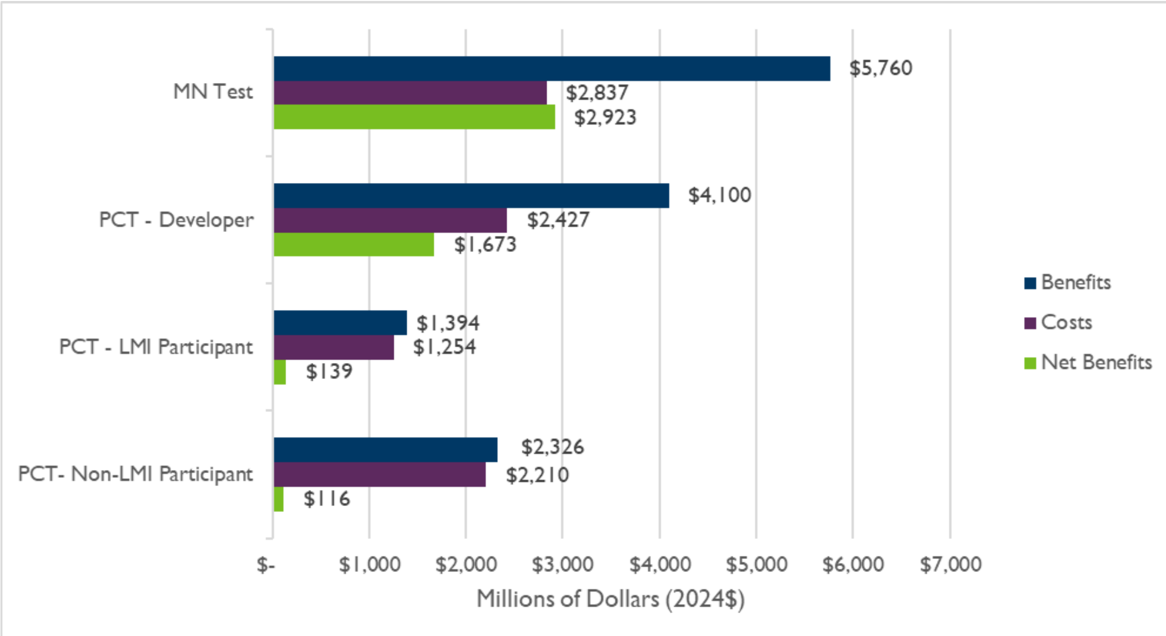
This figure shows the net present value of the benefits, costs, and net benefits of the LMI-Accessible CSG Program experienced by non-LMI subscribers under the Participant Cost Test. Net benefits are calculated as the benefits minus the costs.

The difference in results between the Participant Cost Test results for LMI and non-LMI subscribers is due to the different total numbers of LMI and non-LMI subscribers assumed in these estimates, as well as the different bill credit and subscription costs for each type of subscriber.

Summary of Benefit-Cost Analysis Test Results

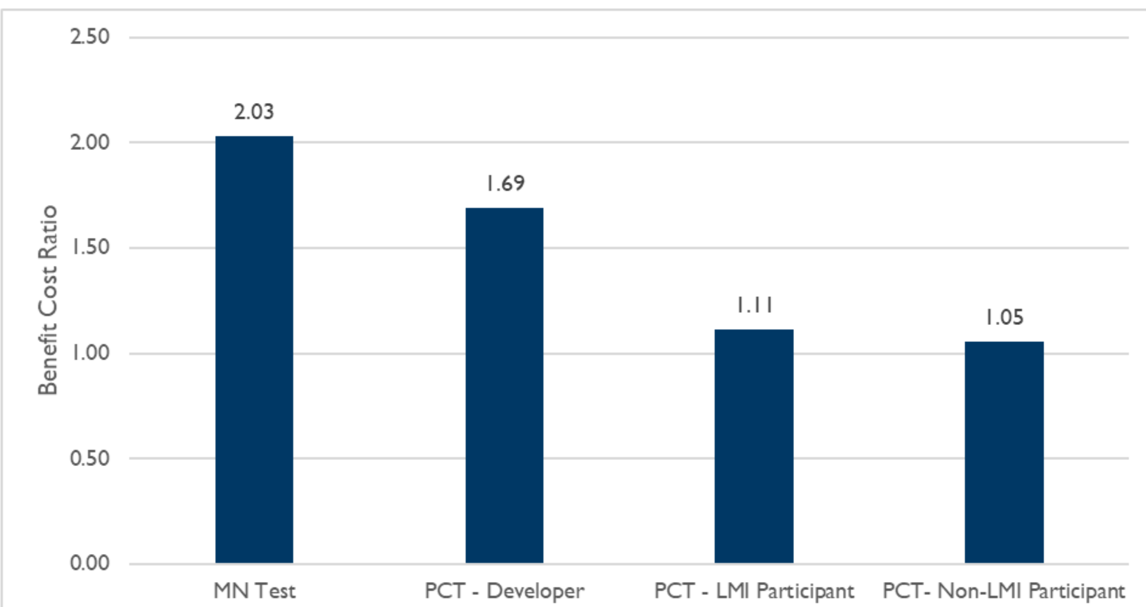
All cost tests resulted in positive net benefits, meaning that the CSG program may be considered cost effective from the perspective of the Minnesota Test as well as the Participant Cost Tests for developers and LMI and non-LMI subscribers. Net benefits to Minnesota and CSG developers were significantly higher than benefits to subscribers. This is also reflected in the BCRs resulting from the tests, which are summarized in Figure 11 and Figure 12 below.

Figure 11: Summary of cost-effectiveness test results – net present value (millions of dollars 2024$)



This figure compares the results of the Minnesota Test and the Participant Cost Test from the perspective of the developers, LMI subscribers, and non-LMI subscribers. Each cost-effectiveness test has positive net benefits, demonstrating general cost effectiveness. However, the large size of the developer net benefits relative to the LMI and non-LMI participants shows that developers are the participant group most benefiting from the program.

Figure 12: Summary of benefit-cost ratios



This figure compares the benefit-cost ratios of the Minnesota Test and the Participant Cost Test from the perspective of the developers, LMI subscribers, and non-LMI subscribers. A benefit-cost ratio greater than one demonstrates that benefits exceed costs. Note that the category of "developer" is broad and encompasses multiple *parties and firms that may be engaged in the installation and operation and maintenance of community solar gardens such as local landowners, financiers, and EPCs.*

4.4 Rate, Bill, and Participation Impacts Analysis Results

Background on Rate, Bill, and Participation Impacts Analyses

A rate, bill, and participation impacts analysis (RBPIA) produces estimates of program impacts on rates and bills, given participation rates and the effect of the program on all ratepayers in addition to any participation-specific impacts. RBPIAs can be considered in concert with BCAs, as RBPIAs provide different information regarding the financial impact of programs on ratepayers. While benefit-cost analyses indicate whether the overall benefits exceed costs, regardless of how the benefits and costs are distributed across different customers, RBPIA indicates how the rates and bills of groups of customers are impacted relative to their current rates and bills. Per the *National Standard Practice Manual for Benefit-cost Analysis of Distributed Energy Resources* (NSPM), RBPIA is useful in indicating "the extent to which DER investments might lead to distributional equity or cost allocation concerns."[85]

The analysis presented herein provides a granular view of subscribers and non-subscribers according to the differential treatment afforded certain subgroups (e.g., cost protection for low-income non-subscribing customers) as well as the differential benefits of each type of subscriber.

In general, an RBPIA utilizes the same data inputs as a utility cost test BCA, focusing on the utility system impacts of the program. Avoided costs (i.e., utility system benefits) exert downward pressure on rates, while program costs and bill credits must be covered by ratepayers and, therefore, exert upward pressure on rates. In the case of the LMI-Accessible CSG Program, bill credits are paid by non-participants (excluding low-income customers) and by subscribers through the fuel clause adjustment.[86] While the CSG program requires the utility to incur costs to support program administration and billing system changes, these costs are not included in the RBPIA because they are fully paid by CSG developers and, thus, on net do not directly impact subscribers or other ratepayers. The costs and benefits included in RBPIA are shown below in Table 23.

Table 23: Costs and benefits included in rate, bill, and participation impacts analysis

	Impact
Benefits	Value of RECs
	Avoided Fuel Cost
	Avoided Plant O&M – Fixed
	Avoided Plant O&M – Variable

[85] National Energy Screen Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM)*, p. xxii, August 2020, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2022/03/NSPM_Methods-Tools-Resources.pdf.

[86] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 16. (May 30, 2024).

	Impact
	Avoided Generation – Capacity
	Avoided Reserve Capacity Cost
	Avoided Transmission Capacity Cost
	Avoided Distribution Capacity Cost
Costs	Bill Credits

Bill impacts are derived from rate impacts and additional information covering the structure of the tariff and any benefits from subscription. Participation estimates provide the number of program beneficiaries relative to the total population of customers. This also provides information about impacts on non-participating populations, who pay for most program costs.

For the LMI-Accessible CSG Program, the report authors evaluated rate and bill impacts for multiple subgroups of customers:

- Non-subscribing low-income residential customers
- Non-subscribing moderate-income residential customers
- Non-subscribing high-income residential customers
- Non-subscribing small commercial customers
- Low-income residential subscribers
- Moderate-income residential subscribers
- High-income residential subscribers
- Small commercial subscribing customers

Methodology for Rate, Bill, and Participation Impacts Analysis

This section documents the inputs and assumptions utilized for the RBPIA. Note that all assumptions from Section 4.2*, Methodology for Benefit-Cost Analysis* Approach to Developing Inputs for Benefit-Cost Analysisare also applied to the RBPIA.

Modeled Tariffs

The two key elements of a customer's rate are the applicable tariff and the customer's billing determinants.

The report authors modeled a residential customer on rate code A01 (Overhead). The fixed charge portion of the tariff was determined by the standard fixed charge described in the tariff. The volumetric charge was modeled as the same volumetric charge used as the bill credit for LMI customers as determined by Commerce's RFP for Community Solar Contracts: the average retail utility energy rate. This volumetric charge is defined as excluding fixed charge collection.[87]

[87] "Request for Proposals," Minnesota Department of Commerce Business Regulation, June 2, 2024, https://mn.gov/commerce/business/rfp.jsp; Xcel Energy, *Report and Petition 2024 Cogeneration and Small Power Production Docket No. E999/PR-24-9*, 4, Schedule C, January 2, 2024.

The components of the residential rate escalate at the same rate as the bill credit benefit: the average price to all users for the fuel electricity from the 2023 AEO Energy Outlook reference case.[88]

The report authors modeled a small commercial customer, representing a public interest subscriber, on tariff A10. The fixed and volumetric charges were derived comparably to the residential tariff and billing determinants. Of note is that small general service customers receive only 75 percent of the applicable average retail rate, lower than 100 percent for LMI residential subscribers and 85 percent for other residential subscribers.

Net Benefit Allocation

Net benefits and net costs refer to the expected net effect of the program on Xcel ratepayers.

In the December 28, 2023, Order in Docket No. E-002/CI-23-335, the Commission determined that net costs should be calculated as the cost of CSG generation (bill credit rate) minus the applicable LMP cost allocated to the residential class by sales.[89] In this analysis, the report authors refer to these net costs as "above-market net costs."

In contrast, all ratepayers experience the benefits of avoided costs associated with the implementation of the LMI-Accessible CSG Program. Thus, for the purposes of determining rate and bill impacts, the net costs include avoided costs.

Cost Allocation

Benefits are allocated based on energy sales because when the utility avoids costs, it is assumed that those avoided costs are allocated as the costs would be allocated. For the set of avoided costs included in this study, the avoided costs would be assigned based on the cost allocation defined by Xcel. This cost allocation is comparable to energy sales by class. Thus, the benefits are allocated to customers based on energy.

The only cost to the utility paid for by other ratepayers is the bill credits. These bill credits are accounted for via a fuel clause adjustment. The report authors' understanding is that the fuel clause adjustment is assigned to customer classes based on energy sales. Thus, the costs are allocated to customers based on energy.

Thus, the benefits and costs of the LMI-Accessible CSG Program are allocated based on energy sales, and the net benefits (net costs) can be similarly allocated to customers based on energy sales.

The report authors assumed that all market and above-market CSG program costs collected through the fuel clause are recovered from Xcel MN ratepayers according to each customer classes' proportion of

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88 Energy Information Administration, Annual Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=~ref2023-d020623a.55-3-AEO2023.1-0&map=ref2023-d020623a.3-3-AEO2023.1-0&ctype=linechart&sourcekey=0.

89 Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 16. (May 30, 2024).

energy sales. The report authors did not explore how studies of ratepayer impacts from the legacy CSG program compared to the report authors' analysis.[90]

Low-Income Customer Protection: Scope of Protection

The law implementing the LMI-Accessible CSG Program includes a clause describing non-subscriber protections. In full, subdivision 11 states that Xcel must do the following:

> *[E]xclude from the fuel adjustment charged to a utility customer the net cost of community solar garden generation under this section if the utility customer*
>
> > *(1) receives or is eligible for bill payment assistance, and*
> >
> > *(2) does not subscribe to a community solar garden under this section.*

The Commission determined that customers who receive this protection are either (inclusive) eligible for a bill payment assistance or income-qualified energy efficiency program or part of the new definition of "low-income household."[91] A possible standard used for this definition is one in which a low-income household "[earns] 80 percent or less of the area median household income for the geographic area in which the low-income household is located, as calculated by the United States Department of Housing and Urban Development."[92]

Low-Income Customer Protection: Income Definitions and Protection

The report authors estimated the size of the above-market net costs based on the actual legacy CSG program market and above-market net costs in 2023.[93] The ratio of above-market costs to total costs to the CGS program is then applied to the total amount of bill credits received in the LMI-Accessible CSG Program to determine the above-market cost of the LMI-Accessible CSG Program. This was estimated to be 25 percent of CSG market costs and 75 percent of CSG above-market costs.

For the purposes of this model, only low-income non-participants are shielded from the above-market net costs of the program, consistent with the provisions of the CSG statute. The scope of protection could be expanded to enhance benefits to LMI customers, but this would require modification of the statute. Within the model, low-income non-participants are assumed to pay none of the above-market costs of the CSG program. The other five residential subgroups each share responsibility for those above-market costs.

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[90] For example, see Gabriel Chan, "Ratepayer Impact Analysis of the legacy CSG program," March 21, 2019, https://chan-lab.umn.edu/ratepayer-impact-of-xcels-community-solar-program.

[91] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 15. (May 30, 2024).

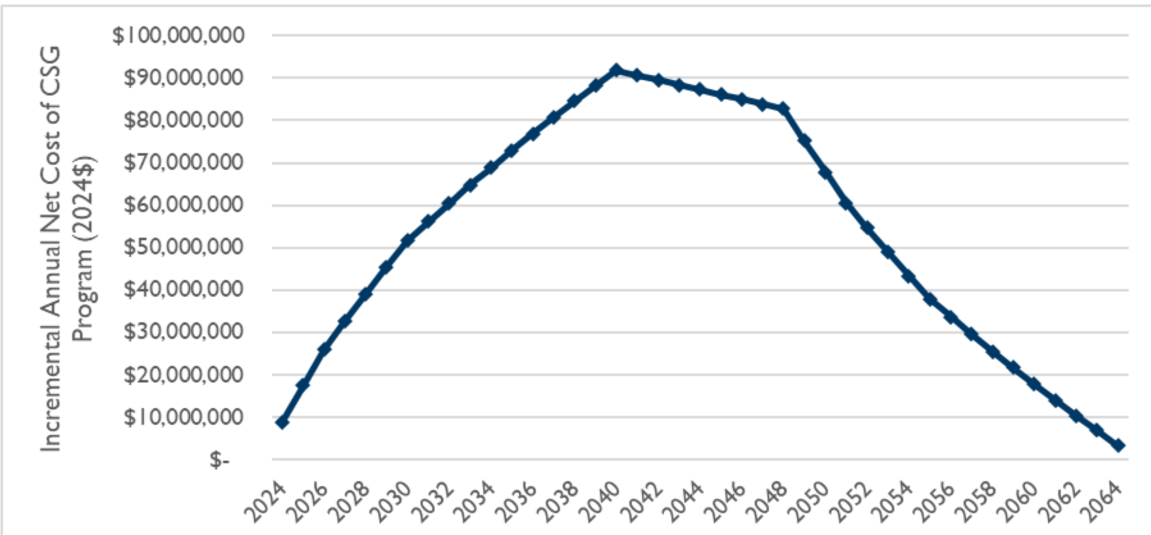
[92] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* Docket No. E-002/M-13-867, Order Implementing New Legislation Governing Community Solar Gardens, p. 15. (May 30, 2024).

[93] Xcel Energy, *Annual True-Up Compliance Report 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges*, Docket No. E002/AA-22-179, March 1, 2024, at 12.

Rate, Bill, and Participation Impacts Analysis Results

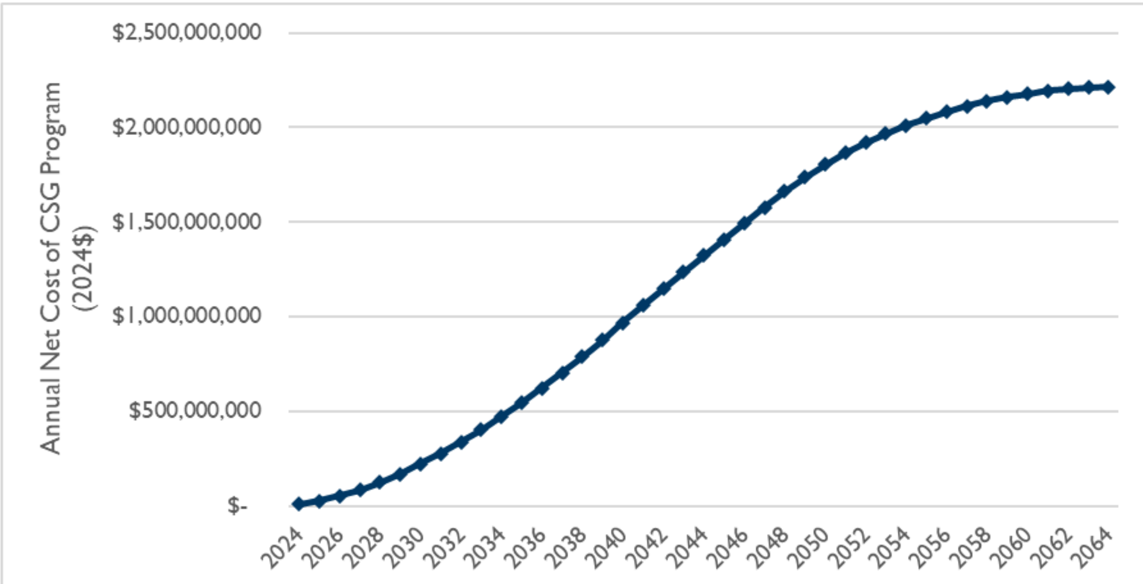
Rate and bill impacts are a function of the net costs—the bill credits less avoided costs—that are borne by non-subscribing customers (excluding low-income non-subscribers) and subscribers. These annual net costs increase as solar facilities are enrolled in the program through 2040, at which time annual net costs are expected to reach $92 million, as shown in Figure 13. In other words, ratepayers are expected to pay $102 million more in utility bills in 2040 than they would that year in a scenario without the program. After 2040, the report authors assume the current iteration of the program ends, and annual net costs decline as systems are retired through 2065. As displayed in Figure 14, the final total cumulative value of net costs in 2064 is estimated at $2.2 billion (undiscounted).

Figure 13: Incremental annual net costs of LMI-Accessible CSG Program (2024$)



This figure shows the incremental annual net costs of the LMI-Accessible CSG Program that are borne by ratepayers. Costs increase through 2040 as additional solar facilities come online because the incremental benefit of every MW of the CSG program is smaller than its cost, resulting in a net cost. The growth of incremental net *costs decreases starting in 2040 because installations are no longer put in service. The decrease occurs more quickly after 2049 as gardens are assumed to be taken out of service after their 25-year service life.*

Figure 14: Cumulative net cost of LMI-Accessible CSG Program (2024$)



This figure presents the cumulative sum of the net costs of the LMI-Accessible CSG Program. Since every year has a net cost, the cumulative net cost increases every year.

After total net costs are calculated, they are allocated to customer classes and, ultimately, to all customers, unless customers are excluded from paying for the program per the CSG statute. The report authors' rate and bill impact analysis focuses on impacts for the residential and small commercial customer classes.

The results of the analysis are shown below at three dates—2030, 2040, and 2050—to allow for a short and long-term perspective on ratepayer impacts. The year 2040 also represents an inflection point in the report authors' model when program participation and costs begin to decline (new capacity additions are assumed to stop in this year), though the first systems installed don't retire until 2049 (25 years after 2024). All customer groups are subsets of the residential class, with the exception of the small commercial customer class.

Table 24: Rate and bill impacts for CSG subscribers and non-subscribers

	Rate Impact (2024$/kWh)			Bill Impact (2024$/month)		
Customer Group	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
LI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
MI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
HI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (2.83)	$ (1.97)	$ (3.56)
Non-Subscribing LI Customer	$ (0.0016)	$ (0.0026)	$ (0.0018)	$ (1.06)	$ (1.96)	$ (1.51)
Non- Subscribing MI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Non- Subscribing HI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Small Commercial Subscriber	$ 0.0016	$ 0.0023	$ 0.0014	$ (17.82)	$ (18.94)	$ (21.54)

	Rate Impact (2024$/kWh)			Bill Impact (2024$/month)		
Non- Subscribing Small Commercial Customer	$ 0.0016	$ 0.0023	$ 0.0014	$ 1.33	$ 2.16	$ 1.46

Table 25: Rate and bill impacts of the LMI-Accessible CSG Program in percentage

	Rate Impact (% of Rate Absent Program)			Bill Impact (% of Bill Absent Program)		
Customer Group	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
LI Subscribers	2.3%	3.4%	2.2%	-7.5%	-6.6%	-7.6%
MI Subscribers	2.3%	3.4%	2.2%	-7.5%	-6.6%	-7.6%
HI Subscribers	2.3%	3.4%	2.2%	-2.7%	-1.7%	-2.8%
Non-Subscribing LI Customer	-1.1%	-1.8%	-1.2%	-1.0%	-1.7%	-1.2%
Non-Subscribing MI Customer	2.3%	3.4%	2.2%	2.1%	3.2%	2.1%
Non-Subscribing HI Customer	2.3%	3.4%	2.2%	2.1%	3.2%	2.1%
Small Commercial Subscriber	1.1%	1.6%	1.0%	-13.5%	-13.1%	-13.6%
Non-Subscribing Small Commercial Customer	1.1%	1.6%	1.0%	1.0%	1.5%	0.9%

All customers other than non-subscribing low-income customers are expected to experience a slight rate increase of about 2 to 3 percent as a result of the above-market program costs collected through the fuel clause adjustment (bill credits more than offset this bill increase for subscribing customers), compared to a scenario without the CSG program. Non-subscribing low-income customers are shielded from paying the above-market costs of the program but should still receive financial benefits from the program through the assumed avoided costs of solar generation.

Despite seeing small rate increases, monthly bill impacts for program subscribers range from around $8 to $10 per month in savings for LMI subscribers to $3 to $4 per month in savings for high-income subscribers as a result of receiving CSG bill credits. Even without bill credits, non-subscribing low-income customers would receive $1 to $2 per month in benefits due to protection from above-market program costs while receiving benefits from the avoided costs of solar generation. These bill savings are equivalent to a 3 to 8 percent bill savings for subscribers, a 1 percent savings for non-subscribing low-income customers, and a 2 to 3 percent bill increase for non-subscribing middle and high-income customers. Small commercial subscribers experience the greatest bill savings of approximately 13 percent.

Because low-income participating customers are not protected from the general ratepayer impacts of above-market program costs, the financial benefits of participation in the CSG program are expected to decrease after 2030 before rising again after solar facilities begin to retire from the program (as projected by the report authors).

Table 26 summarizes the participant impact analysis, which is focused on residential customers. The report authors segment residential participants by low, medium, and high income.

Table 26: Participant impact analysis results

	2030		2040		2050	
Customer Group	Number of Subscribers	Percent of Total Residentia	Number of Subscribers	Percent of Total	Number of	Percent of Total

	2030		2040		2050	
		l Customer s		Residential Customers	Subscrib ers	Residential Customers
LI Subscribers	22,454	1.9%	38,077	3.0%	27,019	1.8%
MI Subscribers	20,912	1.7%	35,463	2.8%	25,164	1.7%
HI Subscribers	7,228	0.6%	12,257	1.0%	8,697	0.6%
Total	**50,593**	**4.2%**	**85,797**	**6.8%**	**60,880**	**4.1%**
Total Residential Customers	1,213,208		1,261,285		1,473,4 16	

Based on the report authors' modeling assumptions, up to 7 percent of residential customers are expected to participate in the LMI-Accessible CSG Program by 2040, with up to 38,000 low-income customers participating and receiving benefits in 2040, equivalent to around 7 percent of total low-income customers. The method of estimating residential customer subgroups is discussed in Section 4.2, *Methodology for Benefit-Cost Analysis*.

4.5 Sensitivi ty and Alternatives Analyses

BCAs and RBPIAs involve several inputs and assumptions, in addition to forecasts over long periods of time, that are inherently uncertain and impossible to estimate precisely. Due to this, sensitivity analyses are useful for exploring the impact of changes to modeling parameters on the results of the analysis. Sensitivity analyses demonstrate the sensitivity of results when key assumptions are varied to reasonable low and high estimates. The broader range of results using low and high sensitivities is likely to contain what will actually occur, thus providing a more accurate depiction of modeling results.

Overview of Sensitivity Analysis

The report authors explored key modeling assumptions that affect overall results as follows:

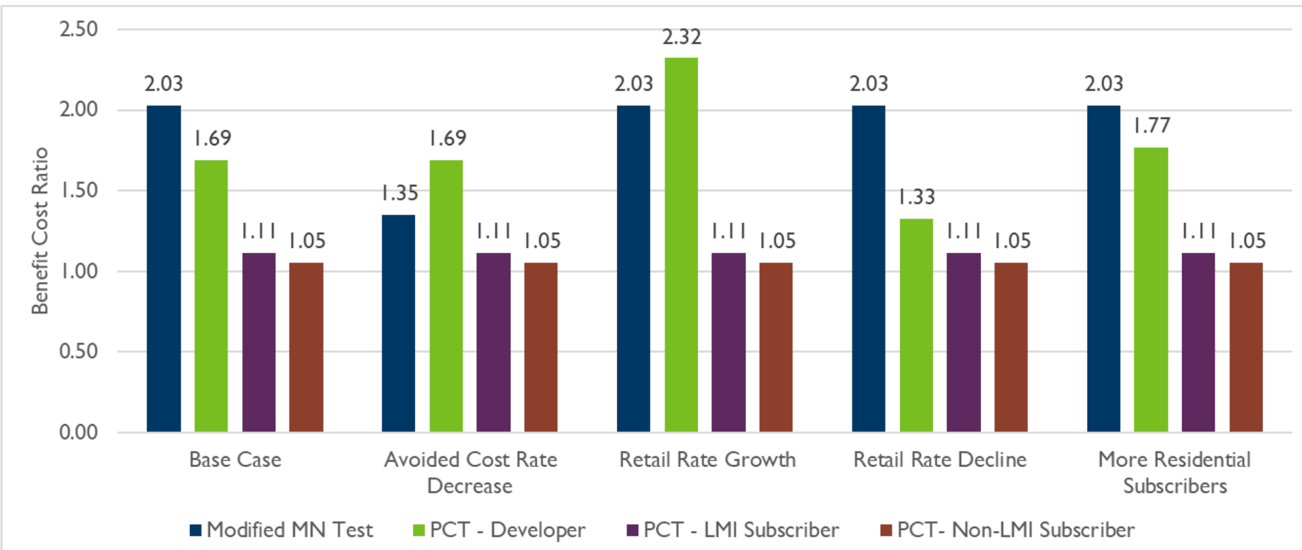
- *Avoided costs:* The report authors examined a sensitivity where avoided costs decay by 5 percent per year in addition to any changes described by the 2023 VOS vintage. As increasing amounts of solar are deployed, avoided costs tend to decline on the margin, so this may be a realistic scenario but will also depend on solar penetration and how load patterns evolve over time.[94] This is compared with the report authors' base case assumption of increases at the rate of inflation.
- *Retail rate trends:* Retail rates (the full rate paid by customers) are inherently difficult to predict, as they vary over time based on multiple factors, including utility expenditure approvals, load (particularly the level of increase or decrease over time), and other factors. The report authors examined two sensitivities: one where retail rates increase over time (2 percent per year above inflation) and one where retail rates decrease over time (by 2 percent per year below inflation). This is compared with the report authors' base assumption of a 0.15 percent decrease per year (below inflation annually).

[94] For example, see Dev Millstein, *The Declining Cost of Solar Power is in a Race With Declining Market Value: Which Will Win?*," Lawrence Berkeley National Laboratory, June 2021, https://eta-publications.lbl.gov/sites/default/files/fact_sheet_solar_and_wind_system_value.pdf.

- *Subscriber mix:* The type of subscriber to the program—residential (LMI vs. high income), commercial, industrial, etc.—affects subscription fees received by developers and the types of participants that benefit from the program. It also affects the total bill credits paid to all participants. The report authors examined sensitivity to the base results wherein a greater number of residential customers subscribe (70 percent of project capacity assigned to LMI residential subscribers, HI residential subscribers, and master-metered affordable housing). This is compared with the report authors' base assumption of 40 percent residential capacity allocation.

Figure 15 shows the results of these sensitivities. The BCR examined shows a relative comparison of benefits and costs. In other words, it is possible for the dollar values of benefits and costs to change, but if they change proportionally, the BCR will remain constant.

Figure 15: Benefit-cost ratios of cost-effectiveness tests, base case vs. sensitivities

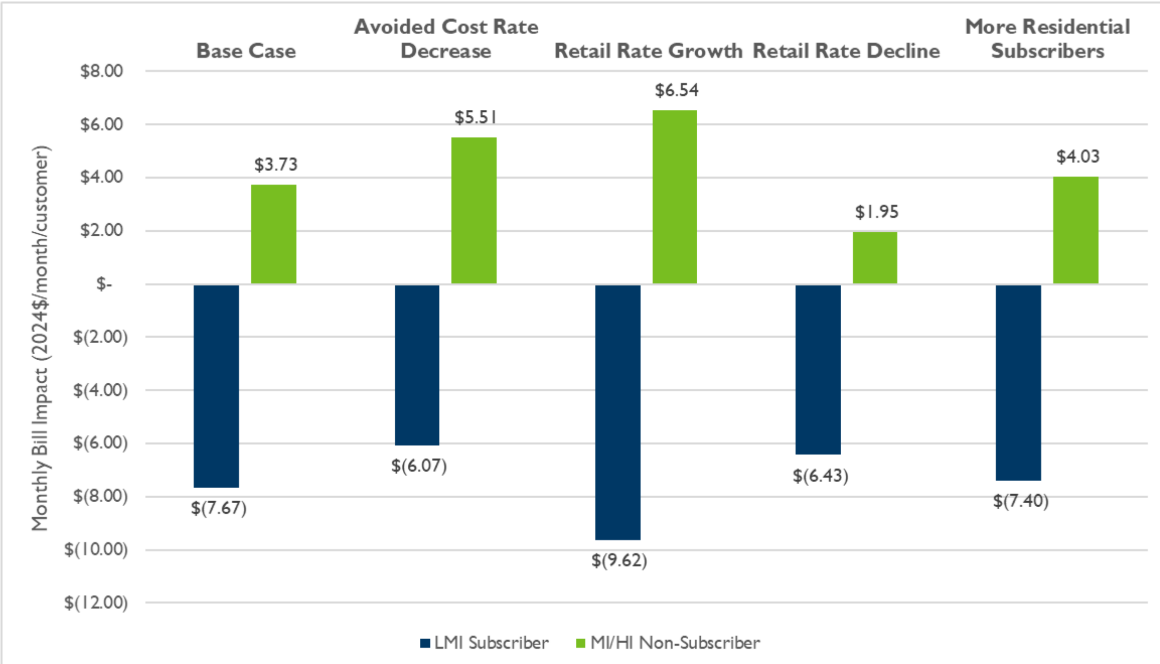


This figure displays the results of the sensitivity analysis on the benefit-cost ratios of each of the four tests. Because none of the sensitivities result in a relative shift of benefits and costs for subscribers, the benefit-cost ratios of the subscriber BCAs do not change. Notably, a higher retail rate, which in turn allows a higher subscription fee, results in a higher benefit-cost ratio for the Developer Participant Cost Test. This is because the underlying installation costs remain constant while the retail rate, and, thus, the developer benefits increase.

Several observations may be drawn from these results. First, the extent of benefits of the CSG program is sensitive to avoided cost assumptions, as seen in the modified Minnesota Test results, which show a significant decrease in the BCR relative to the base case for the avoided cost sensitivity. Second, retail rates affect the dollar value of benefits to participants but not the relative value of benefits versus costs. They primarily impact the Developer Participant Cost Test since subscriber fees are tied to retail rates. Finally, the higher residential participation sensitivity had a slightly positive impact on the BCR for the Developer Participant Cost Test, although this increase may be outweighed by increased customer acquisition costs that are not fully reflected in the report authors' modeling.

Changes in the assumptions reflected in these sensitivities impact the rate and bill analysis results as well. The report authors examined bill impacts in 2040 for LMI subscribers and non-subscribing middle and high-income customers who bear the cost of the program. The report authors analyzed these constituencies because they are the ratepayers targeted for benefits and the non-subscribers who bear the cost of the program, respectively.

Figure 16: Monthly bill impact in 2040 – base case and sensitivities (2024$ per month)



This figure displays the results of the sensitivity analysis on monthly bill impacts in 2040. A negative value indicates a decrease in monthly bills, while a positive value indicates an increase in monthly bills relative to the customers' bills without the LMI-Accessible CSG Program.

In the base case, or the assumed implementation of the LMI-Accessible CSG Program, an average LMI subscriber would save $7.67 per month by subscribing, while a medium- or high-income non-subscriber would have to pay an additional $3.73 per month, relative to no program implementation. An avoided cost decrease would reduce the benefits of every kWh of solar production, thus lowering the overall benefits and impacting customer bills accordingly. Retail rate growth would increase the bill credit and subscription fees while the avoided costs would remain constant, resulting in even larger bill reductions for LMI subscribers and bill increases for non-LMI non-subscribers. A retail rate decline would reduce both the bill credit and subscription fee while securing the same avoided cost benefits, thus resulting in slightly smaller bill decreases for LMI subscribers and significantly lower bill increases for non-LMI non-subscribers.

Alternatives Analysis

Alternatives Analysis Background and Overview

The alternatives examined herein are distinct from the modifications considered in the sensitivity analysis. Alternatives, as construed here, involve changes to the structure of the current LMI-Accessible CSG Program in ways that are not consistent with current law or procuring distributed solar through a wholly different mechanism. While sensitivities examine the impact of changes to key modeling assumptions and inputs, alternatives explore modifications to the current programmatic approach, holding constant all other base case modeling assumptions. The report authors' analysis focuses on potential alternative structures that could improve the cost effectiveness of distributed solar procurement, potentially providing the same or similar benefits at lower costs.

The report authors examine the following alternative CSG program structures:

- A lower subscription fee. In this alternative, subscription fees are 20 percent lower compared to the base case. The report authors do not prescribe a particular mechanism for achieving a lower subscription fee. For example, it could be achieved via expansion in solar garden cooperatives—which may provide lower subscription rates to members and other subscribers—or through Commerce's favoring of solar garden developers offering lower subscription rates when allocating program capacity to prospective developers.
- A higher and lower annual installation limit of double the statutory maximum and half of the statutory maximum, respectively, compared with the report authors' base case.
- Bill credits based on the VOS (around 10 cents per kWh, increasing at 0.15 percent less than the rate of inflation) rather than a percentage of the retail rate. This change would decrease residential bill credits while slightly increasing compensation for commercial customers.

In addition, the report authors evaluate an alternative distributed solar procurement mechanism. The report authors assume the utility can engage in price discovery through competition or other means (e.g., administratively set prices could be set to decrease as quantities of solar are procured) to procure solar at the report authors' modeled cost (levelized cost of energy of all solar produced by solar procured in the program through 2040, discounted to 2024), which includes profit, plus an additional 5 percent, to ensure sufficient returns to investors.[95] This results in a procurement cost of about 5.0 cents per kWh. This allows for lower program costs but is a different structure to the CSG program because it does not include bill credits directed to LMI customers. As a result, no subscription acquisition and management costs are incurred, but such an approach would also not provide any targeted benefits to LMI customers. However, policymakers could consider layering on additional program or tariff structures in conjunction with competitive procurement of solar to provide benefits directly to LMI or even just LI customers. The design of such alternative structures is beyond the scope of this report.

Further, the report authors assume that a comparable amount of distributed solar is built in this alternative relative to the base case because the solar is still procured above cost and allows for the developer to receive a margin.

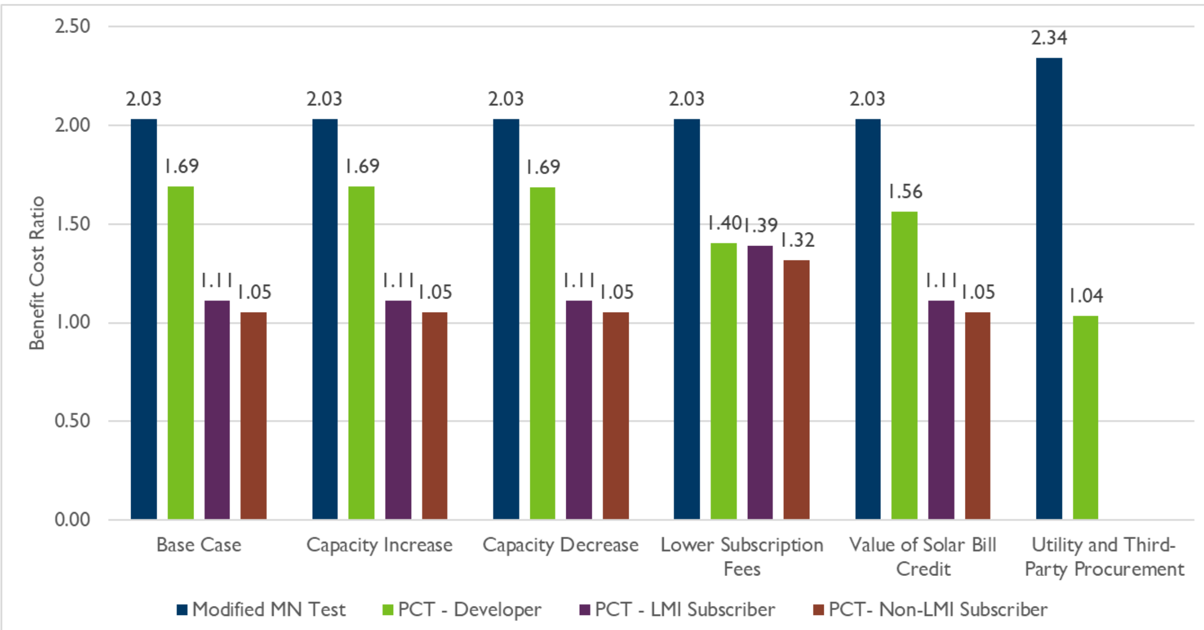
This modeled alternative procurement mechanism approximates the competitive bidding process recently approved by the Commission for Xcel to procure resources to comply with the Distributed Solar Energy Standard (DSES), which requires Xcel to have 3 percent of its total retail electric sales in Minnesota be generated by distributed solar by 2030. Under the competitive bidding process, Xcel will issue RFPs and select projects from bidders based on a scoring metric that includes project costs and

[95] Ramasamy et al. p. 27. Various sources cite profit margin expectations of around 10 to 20 percent. For example, see Republic of Solar, *Is Solar Business Profitable?,* January 18, 2024, https://arka360.com/ros/is-solar-business-profitable/#:~:text=Variables%20such%20as%20the%20initial,between%2015%25%20and%2020%25.

benefits.[96] Under this alternative, solar developers generate revenues from payments from the utility determined through competitive bidding rather than subscription fees, which are a function of a predetermined CSG bill credit rate.

The following figures show the cost effectiveness and bill impact results of these alternatives. Rate impacts are expressed in dollars per month and percentage impact relative to the current configuration of the CSG program.

Figure 17: Benefit-cost ratios of cost-effectiveness tests – base case and alternatives

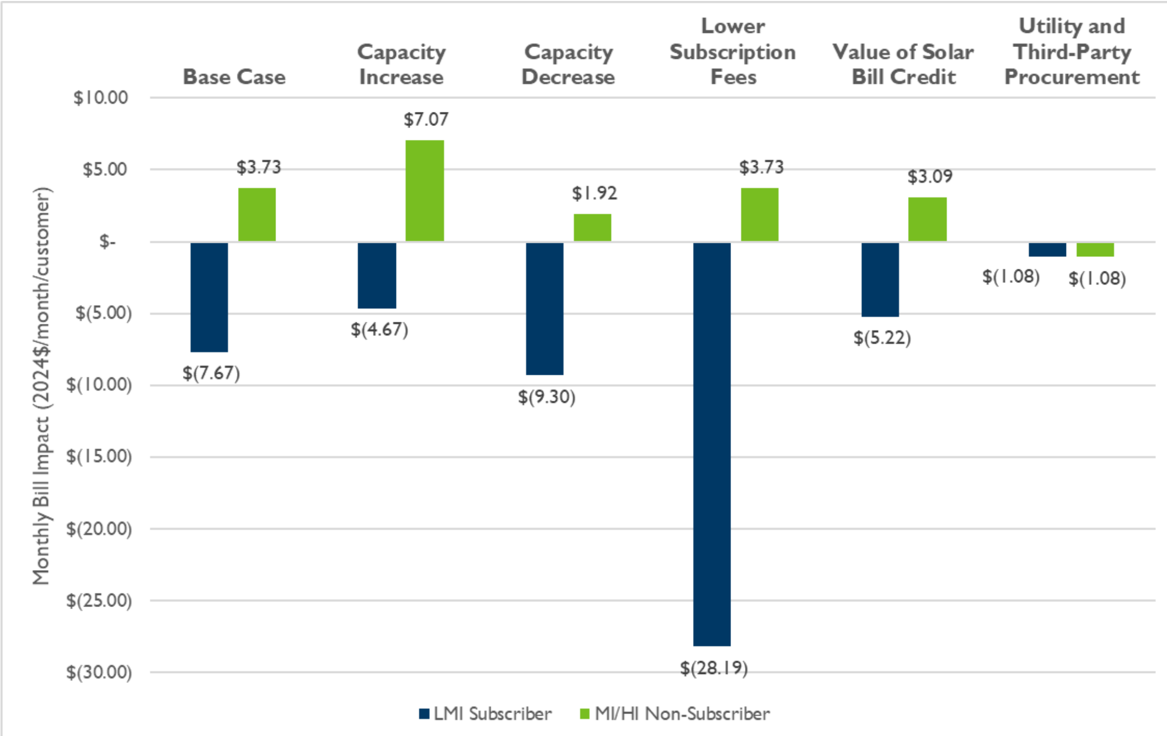


This figure compares the BCA results of the base case (i.e., the current design of the LMI-Accessible CSG Program) to five alternatives.

As capacity increases and decreases, the relative benefits of each MW of CSG remain constant. Thus, the BCRs also remain constant. Lower subscription fees do not change the bill credit, but they do transfer funds from the developers to the subscribers. Notably, the utility and third-party procurement alternative has no participants since it is solely focused on least-cost procurement. The removal of community solar management costs lowers the installation cost, thus increasing the BCR of the modified Minnesota Test. The lower revenue via procurement at cost, relative to the small change in installation and O&M costs caused by removing subscriber management, causes the Developer Participant Cost Test BCR to decrease substantially.

[96] Minnesota Public Utilities Commission, *In the Matter of the Implementation of the New Distributed Solar Energy Standard Pursuant to 2023 Amendments to Minnesota Statutes, Section 216B.1691,* Docket No. E-002, E-015, E-017/CI-23-403, (June 26, 2024).

Figure 18: Monthly bill impact in 2040 – base case and alternatives (2024$ per month)



This figure compares the monthly bill impact results of the base case (i.e., the current design of the LMI-Accessible CSG Program) to five alternatives.

In the base case, an average LMI subscriber would save $7.67 per month by subscribing, while a medium- or high-income non-subscriber would have to pay an additional $3.73 per month relative to no program implementation. The lower subscription fee allows subscribers to have a substantially lower bill. Also, the utility and third-party procurement alternative is the only alternative in which both subscribers and non-subscribers would see bill reductions. This is because the avoided costs of solar are above the full cost paid by ratepayers. There are no subscribers in this modeled alternative, so the subscribers and non-subscribers experience the same bill impacts.

Alternative Analysis Findings

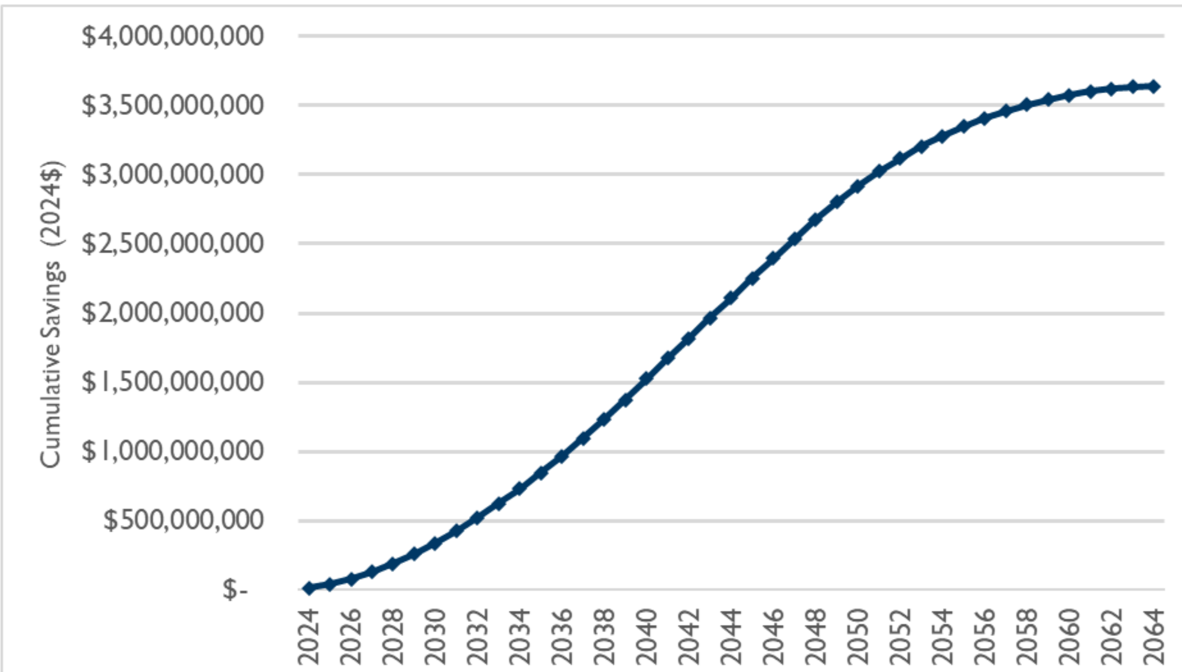
Most alternatives do not affect BCRs—the relative benefits and costs of the program—but do have direct financial consequences on ratepayers. Exceptions include lower BCRs for developers if subscription fees are lowered or the VOS bill credits are adopted. This is because both of these alternatives lower revenues to developers, though the Developer Participant Cost Test is still greater than one in both modeled scenarios. Further, the utility and third-party procurement alternative results in higher benefits for all non-subscribers since the solar installation payment is lower than the avoided costs.

All the alternatives examined affect the rate, bill, and participation impacts analysis. The most significant impacts are seen when lowering subscription fees or through an alternative procurement structure where the utility or a third party procures solar.

Lowering subscription fees allows subscribers to realize significantly greater bill savings by paying a lower subscription fee while receiving the same bill credit.

Solar procurement near cost allows for rate *reductions* for all customers as the modeled cost of solar is less than the avoided costs it generates. However, this arrangement does not include direct bill credits, which provide greater benefits to program subscribers. As previously mentioned, the significant cost savings of the program could be used for programs that target the group of people who would have been LMI subscribers. Nevertheless, ratepayers benefit from this arrangement, saving an additional $1.08 per month relative to the base case. Over the long term, this alternative would save ratepayers $3.6 billion (2024 dollars, undiscounted) for the procurement of the same amount of distributed solar, as shown below.

Figure 19: Cumulative savings of utility or third-party procurement compared to the LMI-Accessible CSG Program (2024$)



This figure presents the cumulative ratepayer savings of utility or third-party solar procurement compared to the LMI-Accessible CSG Program.

4.6 Primary Findings and Conclusions

The report authors' exploration of existing program parameters and alternatives lead to several findings and conclusions. Overall, the report authors' analysis finds that carrying out the CSG program as described by the law will have insignificant solar penetration with concurrent environmental benefits in addition to financial benefits to program participants. However, the program also comes with costs to ratepayers. These costs can be reduced with the use of alternative program structures or alternative procurement mechanisms.

The report authors also find that while the CSG statute appropriately protects LI non-participants from program costs, LI participants are not afforded this protection. LMI program participants would experience higher bill savings if these subscribers did not have to pay CSG program costs, and this would come at a minor cost to non-participants since the report authors' modeling indicates subscribers will comprise around 7 percent of residential customers by 2040. This provision of the law should be modified.

While subscribers experience significant benefits, this comes at a meaningful cost to non-subscribing customers—up to nearly $48 per year, as shown below. This cost is incremental to any other rate increases that occur over the study period.

Table 27: Rate and bill impacts for CSG subscribers and non-subscribers

	Rate Impact (2024$/kWh)			Bill Impact (2024$/month)		
Customer Group	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
LI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
MI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (7.91)	$ (7.67)	$ (9.82)
HI Subscribers	$ 0.0033	$ 0.0049	$ 0.0031	$ (2.83)	$ (1.97)	$ (3.56)
Non-Subscribing LI Customer	$ (0.0016)	$ (0.0026)	$ (0.0018)	$ (1.06)	$ (1.96)	$ (1.51)
Non-Subscribing MI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Non-Subscribing HI Customer	$ 0.0033	$ 0.0049	$ 0.0031	$ 2.25	$ 3.73	$ 2.69
Small Commercial Subscriber	$ 0.0016	$ 0.0023	$ 0.0014	$ (18.94)	$ (18.94)	$ (21.54)
Non-Subscribing Small Commercial Customer	$ 0.0016	$ 0.0023	$ 0.0014	$ 1.33	$ 2.16	$ 1.46

These non-participant impacts can be reduced through modifications to the CSG program or alternative procurement mechanisms. Regarding the latter, the report authors find utility or third-party procurement that involves price discovery through competition or other means results in rate decreases for all customers. However, this alternative does not provide direct financial benefits to subscribers. The competitive bidding process recently approved in Docket CI-23-403 reflects this structure, and a potential expansion of this program should be explored as part of Minnesota's pathway to net zero by 2040.

Regarding potential modifications to the CSG program, a key program parameter is the bill credit level which affects the maximum subscription fee that can be charged by developers. At the same time, developer profits and the viability of the program are a function of solar *costs*, which have no direct relationship to retail rates. The report authors, therefore, recommend the exploration of lower bill crediting schemes that still allow for developer profits and participant benefits. Furthermore, Commerce should prioritize CSG applications with the lowest subscription fees. One way to promote low subscription fee competition among developers is to implement a competitive project selection process for the LMI-Accessible CSG Program. Under this arrangement, projects with lower subscription fees can receive higher scores (as part of a broader set of scoring metrics) that increase their chance of being approved. As provided by the 2023 amendments to § 216B.1641 establishing the LMI-Accessible CSG Program, Commerce has latitude in allocating capacity to developers in consideration of the "scale of financial benefits the community solar garden delivers to LMI subscribers, affordable housing residents, and public interest subscribers." Commerce already considers the scale of financial benefits and other criteria when applying its "Prioritization Scoring Rubric" as part of a second review phase for all completed applications in a given batch where the total capacity of application in that batch exceeds the program capacity cap for the year. Lastly, CSG program subscribers would benefit from greater transparency when evaluating developer subscription fees. A web page that lists developer fees and other important information could provide more competition and transparency in this market and would likely lead to greater program benefits for CSG subscribers.

5.0 DER Interconnection Standards and Procedures

The success of Minnesota's new CSG program, which aims to expand equitable access to solar energy for low-income households, is critically dependent on the ability of community solar projects to be able to interconnect *efficiently and cost effectively* with Xcel's distribution system. Community solar projects, due to their larger size, require more complex interconnection studies, which can be lengthy, expensive, and unpredictable. Incentives in state policy drive significant demand for community solar projects, driven by generous incentives in state policy, and this demand compounds delays in the interconnection study process. These delays impact the speed at which community solar projects can be deployed and, consequently, the speed at which equitable solar access to low-income communities can be delivered.

In addition to interconnection delays, interconnection costs and fees can have a significant impact on project financing, even threatening the financial viability of community solar projects. This impact is especially true for low-income community solar projects where it is not possible to pass any cost overruns or cost increases on to low-income customers. Innovative cost allocation mechanisms that share grid upgrade costs among interconnecting members or that take a multi-beneficiary approach to cost allocation are critical to ensuring that low-income households have access to clean energy.

Methodology

The report authors conducted a regulatory review of documents guiding DER interconnection in Minnesota and a review of utility DER interconnection processes. They also completed a cross-jurisdictional review of DER interconnection processes. In consultation with Commerce, the report authors chose additional jurisdictions to review based on their innovations to improve DER interconnection timelines and costs. The report authors selected to review DER interconnection practices in Illinois, Maryland, and Massachusetts and examined the following:

- Interconnection processes, timelines, and fees
- Interconnection study approaches
- Hosting capacity maps and hosting capacity thresholds
- Cost allocation

To conduct the cross-jurisdictional scan, the report authors conducted a comprehensive literature review of regulations, legislation, utility tariffs, and interconnection guidelines from the three primary states and occasionally reviewed and analyzed additional innovative practices from other jurisdictions. Lastly, the report authors conducted subject matter expert interviews with utility representatives and community solar industry stakeholders.

Key Takeaways and Recommendations

Minnesota's current DER interconnection processes for both CSGs and smaller DERs face efficiency and cost-effectiveness challenges as they adapt to meet consumers' increasing demand for clean energy. In the following sections, report authors review, summarize, and analyze regulatory interconnection documents from Illinois, Maryland, Massachusetts, and Minnesota and provide high-level recommendations for the state to consider that could improve interconnection timelines, fees, costs, and data transparency.

Minnesota faces a unique barrier to maximizing DER interconnection—the rigid hosting capacity limit set by Xcel's technical planning limit (TPL), a feeder or transformer "cap" that limits the equipment to 80 percent of its established system rating plus the daytime minimum load of that equipment. A potential approach to maximizing the efficiency of available grid capacity is to consider a more flexible approach to capacity limits that adjusts based on dynamic, real-time grid conditions through the use of advanced grid sensors and other technologies. If Minnesota were to adopt regulatory changes to allow for flexible capacity limits, it would be among the leading states in the US adopting innovative best practices for enabling dynamic adjustments based on grid conditions.

Minnesota could consider a pilot program to improve the efficient use of available grid capacity. One such pilot could test limited export agreements that allow DER projects to export during periods of available grid capacity and curtail exports during periods of grid capacity constraints under a predetermined agreement with the utility. Similarly, flexible interconnection policies leveraging smart inverters and battery energy storage systems (BESS) would allow DER projects to connect to the grid under dynamic operating conditions. Under flexible interconnection agreements, smart inverters and other advanced technologies would adjust the DER's export power based on the current grid condition.

Across the country, DER projects face long interconnection queues stemming from a high number of speculative projects, long interconnection timelines and missed deadlines, and high costs associated with grid upgrades. One potential approach for addressing missed interconnection deadlines would be for MPUC to implement an enforcement mechanism to ensure that utilities adhere to interconnection timelines. Financial penalties, which the utility would pay to the DER project, could incentivize utilities to stick to application processing and study timelines and, furthermore, to deliver more accurate and transparent cost estimates for any necessary grid upgrades across the various study stages. Such an itemization of costs would provide DER developers with critical cost information throughout the study process and help reduce the number of speculative projects.

Another key recommendation is the adoption of a parallel interconnection process for smaller, residential-scale DERs. These projects have been stalled in the queue behind larger, more complex projects such as CSGs. A separate track could reduce queue backlogs for these smaller projects.

Lastly, the report authors suggest considering updating hosting capacity map values with real-time data at the nodal level. This level of granularity, as well as the dynamic data, would provide DER developers with insights into grid capacity availability, providing critical information for project planning and reducing speculative project applications.

5.1 DER Interconnection in Minnesota

Minnesota Distributed Energy Resource Process (MN DIP)

In Minnesota, DER projects up to 10 MW in size are subject to the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) and compilation of a Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA). The current version of both of these documents (as of September 2024) is available online: MN DIP (Version 2.3). The MN DIA is included as Attachment 7 to the linked MN DIP document.

In 2001, the legislature passed a law in Minnesota Statutes §216B.1611 directing MPUC to "initiate a proceeding… to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity." In response to this directive, MPUC opened Docket No. E-999/CI-01-1023, *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212*. In 2004, MPUC issued an order approving state DG interconnection standards.

These 2004 standards underwent some minor revisions in the following years until MPUC opened a new proceeding in 2016 (Docket No. E-999/CI-16-531, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*). The 2016 proceeding explored whether updates to the 2004 standards were necessary and, if so, what those updates should be. MPUC formally adopted updated new standards—MN DIP and MN DIA—in April 2019.[97] For additional details on the regulatory process by which those standards were developed and have since been revised, refer to Section 2.2, *Program Context*.

MN DIP establishes requirements pertaining to the interconnection application process, which interconnection process applies to a given project, as well as additional considerations, including those related to the interconnection queue, information transparency, and cost allocation. MN DIP includes both generators and BESS technologies as DERs.[98] The interconnection application (MN DIA) has a page where interconnection/interconnecting customers (ICs) can provide energy storage system information if applicable, including system capacity, recharging capacity, and inverter certification. However, there is no *separate* interconnection path or track unique to stand-alone BESS under MN DIP.

This section summarizes these major topics as outlined in MN DIP, and the following section summarizes relevant information from the interconnection agreement process (MN DIA). For full details on all topics, please refer directly to the MN DIP and MN DIA document. All projects seeking to interconnect to a

[97] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, Docket No. E-999/CI-16-521, Order Approving Tariffs with Modifications and Requiring Compliance Filings (April 19, 2019).

[98] The MN DIP Glossary of Terms defines a DER as "A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the MN DIP and MN DIA, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities" (MN DIP Version 2.3, p. 33).

utility's distribution grid in Minnesota (including but not limited to CSG projects) are subject to the MN DIP processes and procedures.

DER interconnection application

The MN DIP requires that utilities allow pre-application reports and interconnection applications to be submitted electronically. For ICs[99] seeking to interconnect in Xcel service territory, Xcel's interconnection application for developers is available on their interconnection web page through their Interconnection Application Portal. With their application, ICs are required to submit several other items:

- Application fees: Application fees vary by the type of interconnection process the project will be undergoing. Projects may undergo the Simplified Process, the Fast Track Process, or the Study Process (see the *DER interconnection processes, timelines, and fees* section below for additional detail on the three different processes).
- A single-line diagram: The single-line diagram requires a signature from a professional engineer licensed in Minnesota for projects utilizing certified equipment greater than 250 kW or non-certified equipment greater than 50 kW.
- Documentation of site control: This can include proof of site ownership, proof of the right to develop DERs on a leased site, or a business agreement indicating the right to develop DERs on a specific site.

For a fee of $300, ICs can submit a pre-application report—an optional report containing project-specific information, including the DER type, project location, nameplate rating, etc.—to the utility that operates the distribution grid where they are seeking to interconnect. In response, the utility must provide the IC with the information described in MN DIP Section 1.4.2, including (but not limited to) the total capacity of the substation area, approximate circuit distance between the proposed point of common coupling and the substation, nominal distribution voltage at the substation, etc., to the extent that the data is available. The pre-application report offers a snapshot-in-time of certain grid characteristics relevant to the IC's specific project, but those conditions are subject to change or be further refined under more detailed review.

The MN DIP also requires that utilities have one or more designated DER interconnection coordinators, who must act as the point person for application questions and be responsible for directing the IC to utility staff who can answer other questions related to the interconnection process. The DER interconnection coordinator is intended to be a resource through which the IC can obtain interconnection-related information in an informal manner.

DER interconnection processes, timelines, and fees

Table 28, below, provides a very high-level overview of the following three different interconnection processes defined in the MN DIP, including associated fees, eligibility requirements, and estimated

[99] The MN DIP defines the Interconnecting Customer (IC) as "the person or entity… whom will be the owner of the DER that proposes to interconnect a DER(s) with the… Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements."

timelines for issuance of the Interconnection Agreement (IA) and overall interconnection process completion (according to timelines described in the MN DIP guidelines).

- Simplified Process
- Fast Track Process
- Study Process

It is important to note, however, that these interconnection processes are variable and highly complex. Notably, it is possible for a project to be eligible for and begin the interconnection process via one process but later be redirected to a different process if a need for additional study or analysis is identified. If a project is redirected to a more intensive process and/or requires additional study, timelines may be significantly expanded. Because we cannot control for these factors in this report, the timelines provided in Table 28 assume that the project fully continues through the interconnection process under which it applied, without diversion to other analysis pathways. For full details associated with each process, please refer directly to the MN DIP.

Given project size thresholds for each process, most proposed CSG facilities under the LMI-Accessible program would likely undergo either the Fast Track or Study process, but all three processes are listed in Table 28.

Table 28: High-Level Overview of Interconnection Processes (MN DIP)

Process	Project Eligibility	Fees*	Timeline†
Simplified	Certified inverter-based DERs ≤20 kW	Up to $100	• **25 business days (BDs)** from utility receipt of complete application (with required fee) until IA issued. • **73 BDs** for total process duration, excluding construction.
Fast Track	DERs that meet the capacity limits defined in MN DIP Section 3.1 that do not otherwise qualify for the Simplified Process	Up to $100 for both certified‡ and non-certified applicants (+ $1/kW for certified, or + $2/kW for non-certified projects)	• **30 BDs** from utility receipt of complete application (with required fee) until IA issued. • **85 BDs** for total process duration, excluding construction—This includes if Supplemental Review is required and results in issuance of an IA (with cost estimates), but does not include a Facilities Study.
Study	DERs that are ineligible for the Simplified or Fast Track processes or that first pursue those processes but fail the necessary screens and studies to continue pursuing interconnection via those tracks	Up to $1,000 plus an additional $2/kW toward required study deposits	**190 BDs** from utility receipt of fully complete application (with the required fee) IA issuance, if no major upgrades to utility facilities are required and the only utility construction necessary is interconnection-related equipment. If upgrades to utility facilities are necessary, this increases to **205 BDs**.

Notes:
*Fees listed in this table do not include costs for additional studies that may be needed based on other study findings or identified upgrade costs. Under MN DIP, ICs are financially responsible for these costs, but they are distinct from the study fee that is due with the interconnection application.

†Timelines listed in this table assume a relatively straightforward completion of the interconnection process, as described in the MN DIP. These timelines do not consider diversion to a different study process or major extensions to the study timeline (e.g., such as through an identified need for a Transmission System Impact Study if a project is identified as potentially causing adverse impacts to the transmission system, etc.). Timelines also exclude the project construction phase.

‡"Certified" facilities are those meeting the qualifications established in Attachment 4, *Certification Codes and Standards*, and Attachment 5, *Certification of Distributed Energy Resource Equipment* in the MN DIP.

MN DIP requires that the utility make a reasonable effort to meet the timelines described. If the utility is unable to meet a specific timeline, they are obligated to inform the IC of the reason for the delay and provide an updated completion date for the specific task or step in the process.

Queue considerations

Upon determining that an interconnection application is complete, the utility assigns the project a position in the interconnection queue ("queue position"), which is based on geographic conditions (e.g., feeder line, substation, etc.). This queue position indicates the project's place in the queue, relative to all other proposed projects with complete, valid, and current interconnection applications. Xcel manages the interconnection queue for all DG projects seeking to interconnect to the company's distribution grid in Minnesota, including both CSG projects and non-CSG projects. DG projects seeking to interconnect in other utility service territories would receive a queue position in that utility's queue.

MN DIP requires that any utility that receives at least 40 interconnection applications in a year maintain a publicly available interconnection queue (updated on a monthly basis) containing, at a minimum, the following:

- Interconnection application or queue number
- Date the utility deemed the interconnection application complete
- The interconnection process track for each project (Simplified, Fast Track, or Study Process)
- Capacity of the proposed DER
- DER type (e.g., solar, storage, etc.)
- Proposed DER location by geographic region (e.g., feeder location on utility's system, line section, etc.)
- Project's status in the interconnection process

Xcel uses a project's queue position to determine what cost upgrades (if any) an individual project would be responsible for if they continue to pursue interconnection. For example, Projects A, B, C, and D may be proposed on the same circuit, but the circuit only has capacity for Projects A–C and *part* of Project D without requiring upgrades to Xcel's system. The queue positions between these four projects help Xcel determine the upgrade costs that Project D would be responsible for if the IC still wishes to pursue the interconnection process without project modification.

In spring 2023, the Minnesota Legislature passed HF 2310 (the Omnibus appropriations bill for environment, natural resources, climate, and energy finance and policy), which contained the following provision:

> ***Article 12, Energy Policy, §75: Public Utilities Commission Docket; Interconnection.*** *No later than September 1, 2023, the commission shall open a proceeding to establish interconnection procedures that allow customer-sited distributed generation projects up to 40 kilowatts alternating current in capacity to be processed according to schedules specified in the Minnesota Distributed Energy Resources Interconnection Process, giving such projects priority over larger projects that may enjoy superior positions in the processing queue.*

As described in greater detail in Section 2.2*, Program Context*, MPUC opened a docket in accordance with this legislative directive and, in April 2024, issued an order establishing that Xcel maintain two administrative interconnection queues: One being the geographic-based queue described above (i.e., by feeder line, substation, etc.), and the other being a priority queue for these smaller customer-owned projects under 40kW.[100] CSG projects would qualify for the former non-priority queue.

In its April 2024 order, MPUC also directed Xcel to include the following data pertaining to the two queues in their quarterly and annual interconnection compliance filings:

- The number of small DER applications interconnected under the new "prioritization" framework and the interconnection queue timelines for those small DERs (compared to timelines under the single-queue approach).
- Interconnection queue timelines for large DER applications, which are not subject to the priority queue, and, if needed, a discussion of issues large DER applications may be facing.

Xcel's most recent quarterly compliance filings are available for review in Docket No. E999/CO-16-521.

Approach to conducting interconnection studies

MN DIP Section 1.8.3 establishes that applications be evaluated serially (e.g., projects are studied individually based on the date/time they submitted their application) but allows for projects to be studied in a group if the utility and the ICs that would be grouped together for study are in agreement. Historically, Xcel has generally evaluated interconnection applications via the first-come, first-served serial approach.

For several years, small projects less than 40 kW have been studied in parallel with other small projects. Under this approach, a project undergoes interconnection screens with the assumption that the projects "ahead" of it in the queue are interconnected to the system (except in cases in which feeder constraints are known).[101] These small projects are now studied in their own administrative "priority" interconnection queue in accordance with MPUC's April 2024 Order in Docket No. E-999/CI-16-521.[102]

In its March 31, 2022, Order, MPUC directed Xcel to expand this parallel study approach to Fast Track applications in areas without known capacity constraints. In this same Order, MPUC also directed Xcel to conduct a pilot of mandatory group/cluster studies for areas with three or more Fast Track applications larger than 40 kW that cannot otherwise be reviewed in parallel due to grid constraints. Under this pilot, projects would be grouped together for the System Impact Study and then the Facilities Study. MPUC also directed Xcel to convene a workgroup to discuss and finalize group study pilot process details. In

[100] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, E-999/CI-16-521*, Order Establishing a Two-Queue System, Directing Further Discussions, and Addressing Miscellaneous Matters (April 15, 2024).

[101] Minnesota Distributed Generation Working Group (DGWG), In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, E-999/CI-16-521, DGWG Subgroup Reports: MN DIP Reporting Update Subgroup (March 24, 2021).

[102] MPUC's April 2024 Order directed Xcel to administer a "priority" queue for these smaller DER projects and a "general" queue for all other projects. This followed several years during which Xcel studied these smaller projects under a parallel approach, and in March 2022 (Order Modifying Practices and Setting Reporting Requirements in Docket No. E-999/CI-16-521), MPUC directed that Xcel expand this approach to qualifying "fast-track" projects.

September 2022, Xcel submitted their group study pilot in accordance with MPUC's directive.[103] Xcel stated the following on page 4 of its filing to MPUC:

> *The Pilot shows that the cluster study process helps to further vet the viability of projects that previously had high estimated interconnection costs by examining whether grouping projects in a cluster will result in a lower cost per project. The pilot study data show that cluster studies help advance the System Impact Study process, but typically show significant upgrade costs that prohibit projects moving forward. These results are not unexpected given the order directed the pilot study to analyze interconnection at congested feeders with technical or capacity constraints. However, costs can be split amongst willing group study participants.*

In its *2024 Interconnections: Generic Standards for Interconnection and Operation of Distributed Generation Facilities* compliance filing (August 15, 2024), Xcel stated that 172 total interconnection applications either completed or were undergoing group studies between 2022–2024. Of those 172 applications, 13.4 percent have a complected interconnection agreement, 3 percent are undergoing system impact studies, 10.4 percent are on hold while waiting for other projects in the queue to complete their own study phase, and 73.2 percent have withdrawn their interconnection application. Xcel will continue to report on the group study pilot.

Cost allocation

Under MN DIP, the IC is financially responsible for the cost of studies required throughout the interconnection process, as well as for interconnection facilities (including those required on the utility's system) and marginal upgrades to the distribution system made as a result of the interconnection.

In directing Xcel to conduct a group study pilot, MPUC stated that the group study model would likely better distribute costs across a range of projects rather than burden any single project with upgrade costs, as occurs under a serial study process. Further, MPUC's March 2022 Order directing the group study pilot also required that Xcel report on the general approach to cost allocation utilized in the process.[104] Exact cost data in Xcel's Group Study Pilot filing is not publicly available, but Xcel does state in Attachment A to its Group Study Pilot compliance filing that the study indicates that the clustered approach does enable costs to be split among projects that are willing and able to pay.

In November 2022, MPUC approved a cost-sharing framework for projects less than or equal to 40 kW. The intent was to prevent very small (i.e., likely non-CSG) projects from being burdened with major grid upgrade costs. This cost-sharing framework requires that Xcel establish a cost-sharing fund. All eligible projects (e.g., 40 kW or under) would contribute to this fund via a $200 application fee; any eligible projects that do trigger distribution system upgrade needs could use up to $15,000 from this fund to

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[103] Xcel Energy, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Compliance – Group Study Pilot (September 30, 2022).

[104] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Order Modifying Practices and Setting Reporting Requirements (March 31, 2022).

help pay for those upgrades. Though this fund is not intended for CSG facilities, it provides a protective financial measure for small projects on potentially congested parts of Xcel's distribution system.

Hosting Capacity Mapping and Capacity Limits

In addition to the queue data requirements under MN DIP (described above), Xcel is obligated to provide distribution system hosting capacity information. Information about hosting capacity enables developers to better understand how much capacity may be available on a given circuit, which can help them make more informed project siting and sizing decisions.

In a June 2016 Order in Docket No. E-002/M-15-962, MPUC directed Xcel to do the following:[105]

> *3. Xcel shall complete and file by December 1, 2016, for inclusion in the 2015 Biennial Distribution-Grid-Modernization Report, a distribution-system study that*
>
> > *a. includes the initial analysis of the hosting capacity of each feeder on the Xcel distribution system for small-scale distributed-generation resources, defined as resources that are 1 MW or less; and*
> >
> > *b. identifies potential distribution upgrades necessary to support expected distributed generation resource additions including, in aggregate, distributed-generation resources that are in the Company's integrated-resource-plan filings and those that are active in the Company's community-solar-garden process.*

This Order was in response to a legislative directive that required utilities operating under multi-year rate plans to conduct a distribution system study for inclusion in their biennial report. Xcel submitted its first distribution system study that year, including feeder-specific hosting capacity information.[106] Following Xcel's filing, MPUC issued a Notice of Comment seeking perspectives on whether there were any potential areas of improvements or modifications to the Xcel's hosting capacity information that would make future filings more useful. Several parties suggested that making the information available as a map would be helpful. Accordingly, in that same proceeding, MPUC issued the following order in August 2017:[107]

> *3. Xcel shall provide a color-coded, map-based representation of the available Hosting Capacity down to the feeder level. This information should be provided to the extent it is consistent with what Xcel believes are legitimate security concerns. If security concerns arise, Xcel shall explain in detail the basis for those concerns.*

In subsequent years and in response to Xcel's annual filings, MPUC issued additional orders further refining the details and level of granularity required in the annual reports and the hosting capacity map.

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105 Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Docket No. E-002/M-15-962, Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. §216B.2425 and Requiring Distribution Study (June 28, 2016).

106 Xcel Energy, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Docket No. E-002/M-15-962, Distribution System Study – Distribution Grid Modernization Report (December 1, 2016).

107 Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Docket No. E-002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report (August 1, 2017).

In 2020, MPUC issued an order directing that the company provide additional information for each feeder, including transformer name, feeder type, absolute minimum load on the feeder, and more (on both the map and via a downloadable spreadsheet format). In that order, MPUC established the following:

> *Xcel's future [hosting capacity analysis] reports must be detailed enough to provide developers with a reliable estimate of the available level of hosting capacity at the feeder and sub-feeder levels at the time of submittal of the report to the extent practicable. The information should be sufficient to provide developers with a starting point for interconnection applications*.[108]

Xcel's hosting capacity map is available on its website, along with resources that include a guide for using the map, hosting capacity data spreadsheets, and the company's most recent hosting capacity analysis report.

Technical Planning Limits

Minnesota's Technical Interconnection and Interoperability Requirements (TIIR)—a guidance document that outlines statewide specifications and technical standards for DER interconnection—acknowledges that "*with so many variations in [utility] designs, it becomes complex to create a single set of interconnection requirements that fits all DER interconnection situations. The [utility] must maintain a level of engineering judgment in order to interconnect the wide range of technologies over a variety of [utility] and DER characteristics and designs,*" in accordance with industry standards and good practice (TIIR pg. 1).

While the TIIR establishes certain specifications related to appropriate default equipment parameters and settings, voltage clearing requirements, and more, it also allows the utility to make additional decisions beyond the scope of described standards in accordance with specific distribution system management needs.

For Xcel, one such practice has been implementing the DER TPL. In Xcel's DER Interconnection Engineering Practice – Technical Planning Limits summary document, the company states that increased DER penetration on its distribution system has brought the grid closer to its thermal limit. Xcel states that potential pathways to ensure continued system safety and reliability with the increase of DERs on the system could include DER curtailment or the TPL.

The TPL establishes a cap on the feeder or transformer, limiting the equipment to 80 percent of its established system rating plus the daytime minimum load of that equipment. In practice, this cap means that the point at which a proposed DER seeking to interconnect may trigger a need for upgrades is "lower" than it would be if there were no TPL, as the "ceiling" on a given feeder or transformer has been reduced. Parties have expressed opposition to Xcel's TPL approach, but MPUC has not disallowed its

[108] Minnesota Public Utilities Commission, *In the Matter of Xcel's 2019 Hosting Capacity Analysis Report*, Docket No. E-002/M-19-685, Order Accepting Report and Setting Further Requirements (July 31, 2020).

use, stating that the topic requires further study and discussion and directing Xcel to include this information in quarterly compliance filings.[109]

5.2 Cross-Jurisdictional Analysis: Interconnection Practices

This section of the report examines the impacts of community solar—and DERs more broadly—on interconnection timelines and costs. Community solar-enabling legislation across jurisdictions has resulted in rapid deployment of community solar projects, which in turn has impacted the interconnection process—largely bogging down the queue and utilizing any remaining capacity on the distribution system. Initial community solar projects were able to make use of available hosting capacity on the distribution system, but as more community solar projects applied for interconnection, these larger and more complex projects contributed to interconnection process delays and cost increases. Many mid- to large-sized DER projects now face long interconnection queue timelines and high system upgrade costs.

However, obtaining granular data specifically related to community solar interconnection proved a challenge, and report authors were unable to directly assess how community solar (as opposed to solar more broadly or all distributed resources) impacts interconnection timelines and costs. Thus, the narrative and analysis below offer a broader examination of interconnection practices from multiple jurisdictions.

Based on direction from Commerce, the following cross-jurisdictional scan reviews DER interconnection practices in Illinois, Massachusetts, and Maryland and focuses on the largest investor-owned utility (IOU) in each state. In this section, the report authors aim to offer insights into how different interconnection regulations and utility tariffs approach and impact the deployment of DERs. The scan provides an overview of the key policies and procedures in these states, focusing on critical areas for comparison, such as the following:

- interconnection processes, timelines, and fees
- interconnection study approaches and innovations
- hosting capacity maps and hosting capacity thresholds
- cost allocation frameworks

These processes and approaches all impact the ability of DERs to efficiently and cost effectively interconnect to the distribution system and can have a significant impact on project viability.

Interconnection processes, timelines, and fees include the initial application process and associated fees, initial screenings, and grid impact studies (e.g., fast-track, standard, or complex studies) along with potential system upgrade costs, interconnection approval, and final interconnection agreement. These

[109] MnSEIA, Fresh Energy, and IREC, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. §216B.1611,* Docket No. E999/CI-16-521, Objection of Minnesota Solar Energy Industries Association, Fresh Energy & Interstate Renewable Energy Council to Implementation of Xcel's DER Technical Planning Limit before Commission Review (September 28, 2021).

Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. §216B.1611,* Docket No. E999/CI-16-521, Order Modifying Practices and Setting Reporting Requirements (March 31, 2022).

processes vary across jurisdictions and can significantly impact DER project developers through project delays and significant unforeseen upgrade costs.

Interconnection study approaches refer to how a utility assesses the interconnecting DER's impact on the distribution grid. This includes an analysis to ensure that the utility can continue to deliver safe and reliable electric service with the requested interconnection. There are two common study approaches for distribution system impacts: a serial approach and a group study approach (sometimes referred to as a "cluster study"). Both approaches are described in detail below, including how each study approach impacts interconnection speeds and costs. Group studies are perceived to offer coordinated interconnection study efficiency and cost-sharing fairness through the streamlined approach of studying multiple projects simultaneously.

Hosting capacity maps are utility-developed online interactive tools that display available hosting capacity at the substation or feeder level and are considered an important tool for directing DER developers to areas of the grid where interconnection is possible without triggering extensive and expensive grid upgrades. However, the level of data transparency, the grid attributes included in the hosting capacity methodology, and the frequency at which the utility updates the hosting capacity map all determine the usefulness of the tool. Hosting capacity thresholds are similar to Xcel's TPL in that the threshold indicates the hosting capacity above which a new DER interconnection would trigger the need for a system upgrade.

Cost allocation frameworks refer to how interconnection costs—including any system upgrade costs—are distributed among interconnecting DER projects, the utility, and ratepayers. Common costs include study costs and grid upgrade costs triggered by the interconnecting DER(s). The way costs are allocated can significantly impact the financial viability of DER projects, especially small- to medium-sized projects and those serving low-income customers.

The interconnection practices evaluated in the cross-jurisdictional scan provide a useful comparison for understanding and evaluating the opportunities and challenges associated with high levels of DER interconnection. The sections below highlight differences related to the following items:

- timelines for interconnection approval for different sizes of DERs ranging from several weeks to several months
- interconnection study approaches from serial to group
- level of data and data transparency offered in hosting capacity maps
- cost allocation methodologies ranging from the "cost-causer pays" method to the more equitable approach of multi-beneficiary cost allocation

By looking across these three jurisdictions, the report authors aimed to focus on solutions (e.g., improved hosting capacity map data) and innovations (e.g., multi-beneficiary cost-sharing) that Minnesota could consider to improve DER interconnection timelines, reduce DER interconnection costs, and ultimately help meet Minnesota's equitable clean energy goals.

Key Takeaways and Recommendations

The following section summarizes key points of comparison from three other jurisdictions—Illinois, Maryland, and Massachusetts—along with recommendations for Minnesota's consideration. The recommendations suggest opportunities for improving interconnection efficiency and costs for both interconnecting community solar gardens and smaller DER projects. The recommendations offered below aim to support smaller DER (e.g., residential scale) interconnection without projects facing long queue timelines or grid capacity constraints as well as support the efficient and cost-effective interconnection of CSG projects. These include recommendations related to proactive grid investments, multi-beneficiary cost-sharing, dynamic hosting capacity data, and interconnection timeline enforcement. These recommended changes could result in reduced costs for DER developers, improved interconnection timelines, faster DER deployment, and progress toward meeting Minnesota's equitable clean energy goals.

DER Interconnection Process, Timelines, and Fees

The following section highlights DER interconnection processes in Illinois, Maryland, and Massachusetts from the pre-application stage to the final interconnection agreement. Like Minnesota, these three states aim to expand community solar access to low-income customers and have extensive DER interconnection guidelines or standards. For this reason, Illinois, Maryland, and Massachusetts offer potentially valuable points of comparison for how Minnesota's LMI-Accessible CSG Program may impact interconnection.

Each stage in the interconnection process has specific timelines, which differ from state to state, as well as fees based not only on project size but also on the number and kinds of specific studies that are required to ensure that the interconnecting DER does not adversely impact grid reliability and safety. Each state's regulatory commission develops and oversees rules and requirements for these processes, timelines, and fees, which are detailed in utility interconnection tariffs.

Depending on the size and complexity of the interconnecting project, interconnection timelines can range from several weeks to several months, sometimes exceeding multiple years. Smaller DER projects (e.g., rooftop residential solar projects) typically require a shorter simplified interconnection review, whereas larger DER projects (e.g., community solar projects) are more complex and require more detailed, technical studies to assess potential distribution system impacts. Utilities may offer "fast track" or expedited review processes for projects that do not require additional studies and that pass a predetermined set of initial screens; these projects can be small- to medium-sized and can include community-scale projects.

Interconnection timelines can be adversely impacted in several ways, causing delays for DER interconnecting customers. Common causes for timeline delays are summarized below.

- Many utilities are experiencing a growing volume of interconnection applications, which can overwhelm utility staff capacity, interfering with their ability to process applications within specified timelines. This can be exacerbated if the utility has limited staff dedicated to processing DER interconnection applications.
- Developers may submit incomplete interconnection applications with missing or incorrect information. To accurately complete the necessary studies, the utility requires accurate facility-specific information.
- The more complex the DER project (and the more congested the grid), the more extensive and complex grid impact studies become, sometimes even triggering a need to analyze potential

interconnection impacts on the transmission system. This is especially true in constrained areas, which are often areas with high DER penetration.

Utilities charge developers fees for interconnection applications and interconnection studies including any necessary engineering review, and developers are required to pay system upgrade costs if any are identified through the study process.

Cross-jurisdictional comparison

Illinois, Maryland, and Massachusetts each use multiple study tracks for DERs of different sizes and complexity. In each state, small projects that are unlikely to cause system impacts proceed through an expedited process, whereas larger projects that are more likely to cause system impacts undergo more extensive review. All three states also offer a group study option aimed at streamlining the study process and reducing interconnection upgrade costs for individual ICs through more equitable cost recovery mechanisms, some of which include multi-beneficiary cost-sharing.

Interconnection timelines are similar among the three states across the different study "tracks" of varying complexity. Timeline certainty for the interconnection process from initial application to construction is crucial for delivering projects on time and in a cost-effective manner. Timeline delays can cause developers to lose permits, place their land leases in jeopardy, potentially miss time-sensitive incentives, and even jeopardize project financing. In some cases, long delays can impact labor and material costs as these costs increase over time.

Outside of the three-state study area, California introduced financial penalties and stricter oversight for interconnection timeline violations via Electric Rule 21: *Generating Facility Interconnections*, which governs the state's DER interconnection process, including timelines. If a utility misses certain interconnection deadlines (after a set grace period), it may be required to pay a financial penalty to the IC up to $1,000 per day for each day after missing a deadline; the total penalty is capped at $50,000. This penalty framework is expected to incentivize utilities to avoid delays by processing interconnection applications in a timely manner and to support the state in meeting its ambitious clean energy goals.

Colorado's regulators have also taken steps via a settlement with the state's largest IOU—Public Service Company of Colorado (PSCo)—and through Senate Bill 24-218 to ensure that PSCo's interconnection process is timely and efficient. Due to customer complaints over solar interconnection delays, the Colorado Public Utilities Commission (CO PUC) is working to standardize timelines and impose potential fees and/or refunds for missed interconnection deadlines. If implemented, these refund mechanisms would work like a "negative" performance incentive mechanism (PIM) where the utility is incentivized to meet a deadline or be faced with a penalty or refund for not meeting the performance objective (i.e., the specified deadline).

Across the three states, the utilities' interconnection tariffs lay out the terms, conditions, and fees for interconnecting DERs. Generally, the tariffs trigger the fees at the same "stage" in each study process/track (e.g., at the application submission, feasibility study, system impact study, etc.). Pre-application, application, and simple screens or study fees are generally comparable across all three states, but fee variability across the states begins to increase as studies increase in complexity. Study complexity increases cost estimate uncertainty and variability, especially if grid upgrades are triggered.

Utility commissions often have mechanisms to address gross inaccuracies in interconnection cost estimates and may be able to order a fee or cost adjustment if the initial estimate was excessively inaccurate. Commissions may require utilities to provide itemized cost estimates for equipment, labor, and other charges. For example, in Illinois, under Illinois Commerce Commission (ICC) Code Parts 466 and 467, if the cost estimate in the final interconnection system impact study exceeds 50 percent of the estimated cost included in the feasibility study, the utility must provide an itemized list of the components that increased in cost along with a detailed explanation of the reasons for the cost increase.

Recommendations on DER Interconnection Process, Timelines, and Fees

To ensure that interconnection applications and studies are initiated and completed in a timely manner and in accordance with the deadlines set forth in DER interconnection tariffs, MPUC could consider adopting an enforcement mechanism similar to California's Electric Rule 21 or a refund or penalty fee like Colorado's PIM. MPUC could consider updating its interconnection rules, establishing binding timelines for each phase of the DER interconnection process. These deadlines should be supported through a clear and formal enforcement process that could include financial consequences for the utility in instances of gross delays. Additionally, to support timeline compliance, MPUC could consider requiring regular reporting on interconnection timelines. These actions could result in timely project interconnection, making the interconnection process more predictable and reducing interconnection bottlenecks.

Similarly, MPUC could consider steps to reduce variability in cost estimates for grid upgrades, which can change drastically between the system impact study phase and facility study phase. To accomplish this, MPUC could require utilities to provide detailed itemized lists of project labor, equipment, and other costs in both study stages. Cost estimates that differ by more than a set percentage between earlier study phases and the actual final upgrade fee could result in financial consequences for the utility. Financial penalties could incentivize utilities to improve their cost estimate processes, improving cost estimates between early feasibility studies and final facilities studies. More accurate cost estimates can improve DER project viability by reducing financial risk and increasing project bankability. However, it is important to consider that utilities may need to invest in software and tools for improving cost estimates; these costs may result in ratepayer increases. It is likewise important to note that differences in DER interconnection cost estimates between study phases are sometimes due to factors beyond a utility's control. For example, the COVID-19 pandemic led to supply chain disruptions and workforce shortages resulting in higher equipment costs and delays in procurement, all of which impacted interconnection timelines and costs. Because these external factors are beyond an individual utility's control, enforcement mechanisms or penalty frameworks for cost estimate inaccuracies should recognize and account for these external factors when assessing utility performance.

Table 29: High-Level Comparison of Interconnection Processes in Illinois, Maryland, and Massachusetts

Process	Project Eligibility	Fees	Timeline
Massachusetts	*Simplified Radial Network:* For facilities <15 kW single phase or <25kw, and some other specific facilities	Utility can suggest that projects do a group study. Expedited and Standard projects requesting or required to get a pre-application report must pay fee ($100-$750 depending on size).	Total maximum days between application and sending executable agreement is 25-30 **BDs**
	Expedited: For facilities that pass pre-specified screens		45 **BDs**, and 65 **BDs** if supplemental review is required
	Standard: All other systems		135 **BDs**, or 160 **BD**s if the application starts in the expedited process. For standard process complex projects, 200 or more **BDs**
Illinois	*Level 1 (simplified process):* For projects with export capacity of 25 kW or less and nameplate capacity of 50 kW or less	Level 1 = minimum $50	Up to 22 **BDs**
	Level 2 (fast track): For projects 25 kW–5 MW	Level 2= minimum $100 + $1/kW Additional supplemental review costs $1,500	Up to 60 **BDs** if no upgrades/ additional studies needed
	Level 3: For non-exporting systems 50 kW or less	Level 3= $500 + $2/kW	Up to 60 **BDs**
	Level 4: For large facilities less than 10 MVA that don't qualify for Levels 1-3	Level 4= $1,000 + $2/kW	
	Large DER: For systems larger than 10 MVA	Large systems (> 10 MW) = $15,000 Customer pays cost of interconnection feasibility and/or system impact study, if applicable.	

Process	Project Eligibility	Fees	Timeline
Maryland	*Level 1:* For inverter-based facilities with a nameplate capacity of 20 kW or less.	No fee	Within 20 **BDs**
	Level 2: For lab-certified or field-approved facilities with a nameplate capacity of 2 MW or less, connecting to a radial distribution circuit or a spot network limited to serving one customer.	$50 + $1/kW	Within 20 **BDs**
	Level 3: For lab-certified, inverter-based facilities with nameplate capacity up to 50 kW and interconnecting to the load side of an area network, with no export of power into the area network and if no construction of facilities by the utility is required; and facilities with nameplate capacity up to 10 MW and interconnecting to a radial distribution circuit, with no power flow onto the electric distribution system and if no construction of facilities by the utility is required.	$500+ $2/kW	25 **BDs**
	Level 4: For interconnection requests that do not meet the criteria for Level 1-3 or cannot be approved under a Level 1-3 review.	$500+ $2/kW	

Interconnection Study Approaches

This section of the report provides a cross-jurisdictional scan of the various interconnection study approaches employed in Illinois, Maryland, and Massachusetts. DER interconnection study processes vary across states, with different states using a combination of serial and group study methods to optimize grid capacity, manage costs, and reduce project interconnection timelines. In this section, the report authors begin with cross-jurisdictional comparisons and recommendations before providing state-by-state details on the study approaches.

DERs typically undergo either “serial” or “group” interconnection study processes (while some states use the terms “group” and “cluster” interchangeably, cluster studies are more typically used for large transmission system-level DER studies). The serial study process evaluates projects individually in the order in which the interconnection application was received and deemed complete. This straightforward process can work well in situations where the queue consists of simple and/or smaller projects (e.g., all under 25 kW). However, as the volume and complexity of projects seeking to interconnect increases, the queue can become lengthy. Lengthy interconnection queues can significantly impact the community solar (and other DG solar) project viability in several ways, including interfering with developers’ ability to secure financing and/or access time-limited incentives. Long interconnection queues can also contribute to delays in construction and operation. In addition to delaying revenue generation for these projects, projects still need to continue making site lease payments, permit payments, and equipment payments while waiting for interconnection approval.

The group study process allows multiple DER projects applying to interconnect on the same part of the distribution system to be studied as a group. Group studies have the potential to assess grid impacts efficiently and improve interconnection timelines, especially in jurisdictions facing high volumes of larger-scale (e.g., community solar) interconnection requests. However, group studies do not always result in reduced timelines if there is a continued high volume of interconnection requests and if the accompanying cost allocation methodology does not resolve inequitable and expensive grid upgrade costs. Interactions between the interconnection study process and the cost allocation process are closely linked and can impact timelines, costs, and final project development outcomes. In a group study scenario, where grid upgrade costs are shared among the group members, the cost allocation method is more equitable, spreading upgrade costs among all members, but problems can still arise. For example, if an interconnecting group member drops out of the study, the costs increase for the remaining members and can create further delays or financial challenges.

In this section, we introduce flexible interconnection (Flex IX) as an innovative approach that provides flexibility within the serial and group study process. Flex IX integrates with system studies by allowing utilities and developers to evaluate flexible capacity solutions (compared to traditional fixed capacity methods) within both study frameworks. Flex IX enables DERs to shift or adapt their export capacity under certain grid conditions.

Cross-jurisdictional comparison

Illinois utilities use both serial and group study processes depending on the status of available grid capacity and the interconnecting project's size. Illinois has taken steps to allow Flex IX[110] and has rules for managing the amount of electricity exported to the grid using advanced technologies. Similarly, Maryland has recently updated its regulations to adopt Flex IX standards, allowing DERs to moderate their output and avoid extensive upgrades. Despite this recent regulatory innovation to improve interconnection, the state has relied heavily on serial studies for community solar projects. Like Illinois, Massachusetts uses both serial and group studies—the latter particularly used for radial circuits—and has updated its regulatory framework to adopt Flex IX and limited export options for improving DER interconnection.

In Appendix E to its 2023 IDP, Xcel noted that Flex IX methods need further study and that it would work to develop a process and standards for using DERMS to manage Flex IX, beginning with establishing technical requirements for DERMS. In its September 16, 2024 Order accepting Xcel's 2023 IDP, MPUC ordered (Order Point 19) Xcel to pursue a phased approach for developing and implementing Flex IX and DERMs and has directed the Distributed Generation Workgroup (DGWG) to work with the utility on plans for developing static and dynamic Flex IX processes ahead of its next IDP filings on November 1, 2025 (Order point 21).[111] The November 1, 2024, DGWG meeting will kick off Flex IX discussions.

Recommendations on Interconnection Study Approaches

The report authors suggest that Minnesota continue pursuing a Flex IX process or consider expanding pilots that would enable DER projects to connect to the grid under limited export agreements during certain constrained grid conditions. This approach would use advanced technology such as smart inverters and/or battery energy storage to dynamically manage project power export when grid capacity was available and limit or prevent export during periods of constrained capacity. Either a Flex IX pilot or a Flex IX rulemaking process would need to be initiated through MPUC and implemented by Xcel. This approach has the potential to allow more DERs to interconnect without cost-prohibitive grid upgrades, thus allowing for faster interconnection. However, it is important to note that this approach only maximizes the efficient use of *existing* available grid capacity and is not a holistic long-term solution for addressing capacity constraints through grid modernization.

Minnesota could continue its pilot parallel process for small (<40 kW) DERs that typically have minimal impact on grid infrastructure to expedite the interconnection process and help reduce the overall queue bottleneck. As experience is gained, Minnesota could consider increasing the threshold to other sized projects (e.g., <50 kW). These smaller projects often get "stuck" in the interconnection queue behind larger, more complex DER projects such as CSGs.

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[110] Flexible interconnection ("Flex IX") is a term applied to a variety of real-time power control options that allow DERs to access distribution system capacity in times of constrained capacity. These options require coordinated control of DER output, for example, through DERMS or voltage or wattage restraints. The export capacity is limited by an agreed-upon generation curtailment between the DER developer and the utility to stay within the limits of available capacity.

[111] Minnesota Public Utilities Commission, *In the matter of Xcel Energy's 2023 Integrated Distribution Plan,* Docket No. E-002/M-23-452, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024).

Illinois

The Illinois Administrative Code Part 466 regulates the interconnection of DERs, outlining the framework for interconnection study processes, including the group study process. A utility may use either a serial or group study approach, with the specific study process determined by various factors, including the type and size of a project, the specific queue the project is entering, and the congestion in that area.

Serial projects are studied individually in the order in which the utility receives the interconnection application. ComEd uses the serial study approach for most smaller-sized projects. In areas where there is already significant congestion and it is likely that potential grid constraints will necessitate system upgrades, ComEd may use the group study approach to assess multiple projects simultaneously. ComEd takes the following steps to determine whether a group study is warranted: After confirming that the interconnection application is complete, ComEd assigns a queue position to the project based on the date it was received; if other projects are on the same distribution circuit and are directly adjacent in the interconnection queue, the utility informs the applicants of the group study.

Flex IX and limited export DERs are governed by Part 466.75, *Limit-Export and Non-Exporting Distribution Energy Resources Facilities*, which sets rules for managing the amount of electricity exported to the grid through advanced technologies such as energy storage, power control systems, and smart inverters. These regulations were promulgated to support the deployment of clean energy resources while maintaining grid reliability and making efficient use of existing distribution system capacity without triggering the need for grid upgrades. Under Part 466.75, the IC and the utility agree to an export limit, and the IC utilizes technologies like smart inverters to adjust the system output based on the grid conditions, ensuring that the DER system does not export above the limited amount of energy.

Currently, ComEd and Xcel are collaborating with the Pacific Northwest National Laboratory to develop a Flex IX pilot project, which aims to deliver considerations and best practices for an end-to-end Flex IX process. Xcel's pilot specifically targets proposed community solar projects, testing whether these projects can adjust their export levels based on real-time grid conditions to enhance grid reliability without expensive grid upgrades. The pilot also aims to make capacity available for DER interconnection within already constrained areas on the grid.

Massachusetts

In Massachusetts, ICs proposing to interconnect to area networks are studied using a serial approach (MDPU NO. 1468, Standards for Interconnection of Distributed Generation). DER interconnection requests are studied in the order they are received, and their impacts are analyzed sequentially. As additional projects apply for interconnection, the cumulative impacts of preceding queued projects are considered. This study process results in longer processing times for DER projects later in the queue, especially if upgrades are required.

Interconnecting customers who are proposing to interconnect on a radial circuit/Common Study Area are studied using a radial process; all potential projects on a radial line are evaluated in a "cluster" to determine cumulative impacts, which are identified in a group impact study. There are multiple benefits to the group study approach, including faster timelines for interconnection reviews and approvals and the ability to share the costs of system upgrades among all participating DER projects. Costs may then be shared among the DER projects in the group.

Massachusetts has taken steps to address long queue delays, including Flex IX options such as limited export. This short-term solution for integrating more DERs onto the distribution system is referenced in the utility interconnection tariffs (§§ 3.0, 3.4, and 5.0) and Department of Public Utilities (DPU) orders (e.g., MA DPU 19-55 and MA DPU 20-75). DPU 19-55 advanced grid modernization in Massachusetts by directing utilities to consider interconnection applications proposing advanced technologies such as smart inverters, energy storage, and advanced metering infrastructure for more efficient DER interconnection. This order enabled utilities to adopt flexible solutions, such as limiting export options under pre-specified circumstances. As the utility studies potential DER impacts, it may evaluate whether DERs could export to the grid under certain circumstances but cap or limit their export to a pre-specified output at other times, thereby avoiding impacts to grid reliability and safety while also avoiding the need for costly grid upgrades. DPU 20-75 expanded on 19-55 seeking long-term solutions to meet the state's clean energy objectives by considering new system planning processes as well as short-term actions to improve interconnection capacity. Through this order, the DPU outlined power control limiting and dynamic curtailment options.

Maryland

Baltimore Gas and Electric (BGE) uses a serial approach for DER interconnection studies, studying each project in the order in which its application is received. While Maryland did not adopt a permanent community solar program until July 1, 2023, through the passage of House Bill 908, a pilot community solar program had been in effect since 2015. The pilot program had a statewide cap of approximately 418 MW, which the new program removed (but maintained a 5 MW per project cap). It is likely that BGE's interconnection queue is largely made up of community solar projects, which require more detailed and, therefore, lengthier study periods.

Maryland has taken steps to address interconnection timelines and mitigate potential grid impacts from the interconnection of an increasing number of DER projects. Maryland's Public Service Commission (PSC) began taking its first steps toward adopting Flex IX regulations for DERs in 2020 within the Public Conference 44 Proceeding to transform Maryland's electric system. Flex IX standards enable DERs to more effectively use existing hosting capacity by allowing them to moderate their output, thereby avoiding extensive system upgrades. It is a short-term solution to make efficient use of existing capacity and interconnect more DERs. Order No. 89933 paved the way for Maryland utilities to study and interconnect energy storage systems based on net system capacity and proposed use. Following this order, the PSC adopted regulations in January 2024 (Code of Maryland Regulations [COMAR] 20.50.09.06]) that enabled utilities to better integrate smart inverter technologies by requiring utilities to establish default smart inverter settings. In Phase V of the Public Conference 44 Proceedings, additional rules were updated to require utilities to approve interconnection requests while allowing Flex IX options under a limited export agreement, requiring DER curtailments under conditions specified in interconnection agreements (COMAR 20.50.09.06P).

Other Jurisdictions

California's Rule 21 enables interconnection study process innovation by allowing streamlined review and approval of smaller-sized DER projects through a fast track process. Small projects under 3 MW may submit an optional pre-application report request to an IOU and receive information about the proposed interconnection site's available capacity, including substation bus capacity, approximate circuit distance between the proposed project site and the substation, and peak line load estimate.[112] If the area has sufficient availability and the project is unlikely to trigger system upgrades, it may enter the Fast Track study process, where the utility conducts predetermined simplified screens to determine whether the project can interconnect without triggering significant upgrade needs. Projects that pass these screens move directly to interconnection approval, shortening the interconnection timeline from months to weeks. (Note that a Supplemental Review may be needed based on the results of the initial screens; a Supplemental Review requires a nonrefundable $2,500 fee and additional screens. Engineering review is not required.)

Colorado has been actively exploring potential fees and penalties for interconnection delays, which have left thousands of customers waiting for the interconnection of their distributed solar investments. In January 2023, PSCo filed with the CO PUC that it had a backlog of 4,000 solar interconnection applications due to several factors, including an unprecedented volume of interconnection applications, required meter upgrades, necessary distribution grid upgrades, supply chain shortages, and limited staff capacity. Customers were facing a 6–12 month wait to interconnect their DER projects.

In response to customer complaints, the Colorado legislature passed Senate Bill 23-016, *Greenhouse Gas Emission Reduction Measures*, allowing the CO PUC to establish interconnection timelines and fine a retail electric utility up to $2,000 per day for each day that the CO PUC determines that a timeline violation continued. Governor Polis signed the bill on May 11, 2023, and it went into effect on August 7, 2023. In October 2023, PSCo reached a settlement agreement to address interconnection delays, agreeing to improve the interconnection process by hiring additional staff and working through the backlog. In the settlement agreement, PSCo agreed not only to establish standardized timelines but also to create penalties and interconnection fee refunds for missed deadlines.

In April 2024, Senator Chris Hansen introduced Senate Bill 24-218, which Governor Polis signed on May 22, 2024. The new law tasks PSCo with developing near- and long-term plans for addressing the interconnection backlog and setting penalties for missed interconnection timelines. It also contains additional proactive grid investment requirements to enable renewable energy integration. The CO PUC is tasked with ensuring the plan includes adequate staffing levels to comply with state laws for distribution system planning and renewable resource deployment and with opening a rulemaking for establishing interconnection and energization timelines. The bill could allow PSCo to recover grid investment costs across its rate base, with cost recovery capped at a 1.25 percent impact on retail rates. The bill also requires PSCo to include a performance-based framework within its distribution system plan, subject to CO PUC evaluation.

[112] Non-exporting projects and net energy metering projects are eligible regardless of the gross nameplate rating of the proposed project. Exporting projects up to 3 MW may qualify.

Hosting Capacity Mapping and Threshold

Hosting capacity maps provide insights into a distribution system's ability to accommodate DERs without triggering significant upgrades. Fifty-eight utilities across 26 states, including the jurisdictions evaluated in this report, publish hosting capacity maps. While the hosting capacity maps display similar data, data analysis methodologies can vary from utility to utility depending on the goal of the utility and the map's intended purpose. Hosting capacity maps may differ in their data update frequency, the types of constraints studied to determine capacity availability, and the incorporation of future DER deployment scenarios. The more dynamic the data, the more valuable the data is to developers for planning projects. Hosting capacity maps that are updated quarterly are not useful to developers since they only offer a snapshot view of the system's conditions at one particular time in the past. According to one solar developer, even monthly updates provide only directional information. Developers are asking for additional data, data transparency, hosting capacity analysis transparency, real-time/dynamic updates, and increased granularity to be able to propose and finance multimillion-dollar solar projects.

Xcel Energy Minnesota has established the TPL, a hosting capacity threshold that acts as a cap on the amount of DER capacity that can be interconnected to the distribution grid at a specific location without triggering significant system upgrades. The TPL is unique to Xcel MN, but hosting capacity thresholds are common among other utilities in the US. Similar to the TPL, hosting capacity thresholds help DER developers select grid locations with sufficient capacity for DER interconnection without major system upgrades. Whereas Xcel MN's TPL sets the hosting capacity threshold for specific distribution lines or feeders at a static 80 percent above which any interconnecting DERs would trigger and be responsible for paying for significant grid upgrades, other jurisdictions dynamically set limits at individual feeders and/or substations.

The other jurisdictions studied for this report calculate the amount of remaining or "reserve" hosting capacity using various factors beyond voltage levels, such as customer load, customer demographics, and the type of area served, rather than at a static, predetermined level. For example, reserve hosting capacity is likely to be more available at rural feeders versus urban ones.

Hosting capacity thresholds (also called capacity limits) are provided on utility hosting capacity maps. These online maps are regularly updated by utilities to show the maximum amount of DER capacity that could be added at specific locations on the distribution grid without triggering major grid upgrades. Ideally, hosting capacity maps show capacity availability in real-time but are more practically updated monthly. Developers use these maps in their pre-development work (prior to submitting an interconnection application) to identify potential locations where their projects could be interconnected without costly grid upgrades. Hosting capacity maps offer a level of detail and transparency that supports reducing interconnection delays, study timelines, and grid upgrade costs.

Cross-jurisdictional Comparison

None of the IOUs in the jurisdictions reviewed place a predetermined and fixed capacity planning limit like Minnesota's TPL threshold. Instead, Illinois, Maryland, and Massachusetts provide hosting capacity data in hosting capacity maps. The type of data, the level of transparency the data confer to developers, and the frequency of data updates varies among the three states. In Illinois, ComEd provides monthly hosting capacity map updates, providing capacity details down to the feeder and substation level, incorporating overvoltage and overloading. Massachusetts' National Grid also updates its hosting capacity maps monthly and provides granular details (soon to be nodal level), including with and without pending DER projects. Its hosting capacity thresholds are set through feeder-specific power flow and engineering modeling that considers voltage, thermal limits, and other system protection requirements. Lastly, Maryland's BGE provides two different hosting capacity maps—one showing restricted circuits and the other showing available hosting capacity (like the other IOUs). Maryland's BGE calculates its hosting capacity threshold based on voltage, thermal constraints, and system protection requirements.

Recommendations Hosting Capacity Mapping and Threshold

Minnesota could consider implementing a cadence for hosting capacity map updates that improves system visibility and data granularity for developers. Xcel already updates its hosting capacity map on a quarterly basis. The Joint Utilities of New York and utilities in California provide monthly updates to their hosting capacity maps with data affecting interconnection, like queue updates, but the hosting capacity values themselves are not updated monthly. Minnesota could consider similar monthly updates.

Minnesota could also consider a pilot where hosting capacity map values are informed by real-time data; the pilots could include investing in and testing advanced grid sensors, advanced metering infrastructure advanced metering infrastructure, and DERMS.[113] This dynamic real-time data could enhance hosting capacity map value to both grid operators and DER developers when selecting potential points of interconnection (POIs) by providing a more granular view of grid capacity, including greater visibility via nodal-level information in congested areas. Greater visibility into real-time grid conditions is possible through the installation of grid-edge monitoring tools such as grid sensors and advanced metering infrastructure; in turn, DERs can respond by actively managing their energy export to the dynamic grid conditions through smart inverters and DERMS. These technologies can feed real-time grid conditions about transformer loads, voltage stability, and supply and demand and can help developers make more accurate interconnection proposals and reduce the number of speculative interconnection applications; this would, in turn, alleviate interconnection queue congestion, reduce study timelines, and result in faster interconnection timelines. Such a program would need to be developed by Xcel and MPUC, with the agency having regulatory authority over pilot approval and oversight of the pilot.

Minnesota could consider eliminating its fixed TPL approach and transitioning to a dynamic threshold that adjusts in real-time based on grid conditions at the feeder level. Such an approach would account for dynamic grid conditions at the feeder level based on load, thermal limits, and voltage constraints. Such an approach would make more efficient use of available grid capacity and allow more DERs to interconnect to the system. Alternatively, Minnesota could adopt a system similar to Maryland's Reserve Hosting Capacity where a portion of the grid's available capacity is reserved for smaller DERs. Under the latter approach, smaller DER projects could also interconnect faster without getting stuck behind larger, more complex DER projects in the queue. Both these approaches would require MPUC to (1) undergo a new rulemaking to explore alternatives to the TPL and, if the TPL were eliminated, to

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[113] Xcel Energy, *Integrated Distribution Plan 2023-2024*, Docket No. E-002/M-23-452 (November 1, 2023). Xcel is considering grid modernization investments including pilots to test use cases and rate structures for DERMS, energy storage, and electric vehicles via its 2023-2024 Integrated Distribution Plan.

update the state's interconnection standards or (2) amend existing regulations to allow for a reserve hosting capacity.

Illinois

ComEd, Illinois' largest IOU, does not have a technical planning limit similar to Xcel MN's, but it does determine hosting capacity thresholds and makes that information available on its hosting capacity map to help developers identify potential sites for DER interconnection onto specific locations on its distribution circuits.

ComEd calculates its available circuit-level DER hosting capacity for distribution circuits at or below 34kV. By studying the capacity at each of its feeder lines under multiple scenarios, ComEd can determine which feeders are capable of interconnecting additional DERs without system impacts or system upgrades. These automated simulations consider overvoltage and overloading by studying the following:

- feeder design
- existing load
- customer behavior

ComEd's hosting capacity map provides granularity down to the circuit level. The main interactive map page displays township data (6 x 6 miles) and is color-coded. The colors represent the range of the estimated hosting capacity within each township, and a developer can quickly see where there is no capacity available. Users can then click on the map in a particular location to access more granular data down to ¼ x ¼ mile sections. A user can obtain feeder and substation-specific data estimated feeder hosting capacity and substation DER in the queue. Due to the dynamic nature of the grid, the hosting capacity maps are updated periodically. The map lists the "last update date" along with the hosting capacity data.

Massachusetts

National Grid sets feeder-level thresholds to determine how much DER capacity can be added to the system and where without triggering significant infrastructure upgrades. The hosting capacity threshold represents the maximum DER capacity that can be interconnected at a specific location without major upgrades. It displays this information on its regularly updated hosting capacity maps.

The utility calculates its hosting capacity dynamically, calculating the threshold limits via power flow and engineering models at feeders and substations that consider the following:

- existing load on the system at a particular location
- the thermal limits of a particular line or transformer
- the ability to maintain stable voltage levels as more DERs are added
- the impact of additional DER capacity on system protection equipment and power quality

National Grid uses hosting capacity maps to show where there may be additional DER capacity currently available on distribution lines as well as where the grid may be already constrained and unable to interconnect more DERs without a system upgrade. The hosting capacity map is updated monthly with changes to capacity, connected DERs, and pending DERs. A user may choose between two different map layers—one that shows the hosting capacity relative to pending DER projects and another that shows the hosting capacity without the pending DER projects taken into account.

Substation-level and feeder-level data are available with additional details such as hosting capacity, connected and pending DER by technology type, affected system operator status, and substation or feeder information (e.g., operating voltage, ongoing affected system operator studies, substation name). Each feeder and substation information pop-up displays the latest update date.

National Grid notes that it will be adding nodal hosting capacity soon. Nodal maps will have more granular and localized information about distribution capacity, which may be more helpful for the precision planning of DERs in congested areas.

Additionally, National Grid uses scenario-based modeling as part of its broader hosting capacity analysis to forecast future DER growth and its impacts on grid capacity, reliability, and other interconnection considerations. The forecast model is based on a series of scenarios that account for projected load growth, DER adoption rates, regulatory changes, and grid upgrades. This proactive approach allows National Grid to identify and address potential areas with constraints, aiding the utility in understanding how much short- and long-term additional capacity the system needs to interconnect DERs safely while ensuring grid reliability and resilience. Scenario-based modeling and subsequent proactive grid investments (e.g., upgraded substations, distribution feeders, etc.) to accommodate future DER growth are part of the IOU's electric sector modernization plans (ESMPs), reviewed by the Massachusetts Department of Public Utilities' Grid Modernization Advisory Council, established to oversee IOU grid modernization efforts. National Grid's ESMP—called the Future Grid Plan—presents the Advisory Council with a roadmap of the investments needed in the distribution network to meet the state's clean energy goals (established in the Massachusetts Clean Energy and Climate Plan for 2050) over three planning horizons—a 5- and 10-year forecast and a demand assessment through 2050. Elements of the ESMP received regulatory approval through the Grid Modernization Plan (Dockets 15-120, 21-81), while the plan itself received regulatory approval on August 29, 2024, through DPU 24-10, allowing the utility to invest $336 million in proactive grid investments between 2022-2025. Cost recovery for these investments is built into the rate case.

Maryland

BGE, Maryland's largest IOU, does not have a hosting capacity threshold similar to Xcel MN's TPL but, like many other jurisdictions, provides hosting capacity information via two different tools: a PV hosting capacity map and a restricted circuits map. Like the other jurisdictions' hosting capacity maps, BGE's indicates the remaining availability on a feeder to be able to connect DERs before that feeder capacity or other limitations are reached. The latter map, as its name implies, shows where capacity to interconnect DERs is limited or constrained.

In Maryland's Public Service Commission Public Conference 44 Interconnection Work Group's *Small Generator Facility Interconnection* Report (Phase III, 2021), the Work Group discussed the concept of a reserve hosting capacity (threshold) to avoid situations where smaller residential DERs would not be able to interconnect due to a lack of hosting capacity availability from larger interconnecting customers blocking out all the available capacity. The Work Group found that the language in the *Small Generator Interconnection Standards* (COMAR 20.50.09.06) was very clear in that the reserve hosting capacity should not be set administratively to a fixed value, but should vary based on the factors in COMAR 20.50.09.06.

Like the ComEd hosting capacity map (both ComEd and BGE are Exelon companies), an interactive color-coded map shows the estimated hosting capacity at a feeder. If the feeder is on a network line, developers must contact BGE for information about specific line capacity. The hosting capacity maps are updated quarterly.

BGE considers the following as it calculates hosting capacity limits for new DER interconnections:

- voltage limits
- thermal constraints
- system protection requirements

The restricted circuits map displays both “restricted” circuits and “fully restricted” circuits. Fully restricted circuits have reached their maximum installed DER capacity and may not accept additional DER capacity *unless* the developer is willing to pay for a significant system upgrade that would allow them to install their DER system. Restricted circuits signal to developers that the circuit has reached its maximum allowable aggregate amount of large DER generators. Additional small capacity DERs may be accommodated.

Per existing COMAR 20.50.09.06 Hosting Capacity regulations for restricted circuits, a utility may determine the following:

- the amount of reserve hosting capacity based on distributed energy resource forecasts or other factors, including customer density, type of area served, and customer demographics of the circuit
- the aggregate generation of a small generator facility permitted to use an electric distribution circuit’s reserve hosting capacity and publish this information on their website

BGE provides a technical manual that outlines the criteria limits for DERs on its distribution system. On radial distribution feeders, the total limit of large DERs (>250 kW) is based on circuit-specific analysis. Once the aggregate limit is reached, 250 kW or smaller systems can continue to be added until a circuit or substation violation is reached.

The Maryland PSC recently updated COMAR 20.50.09.06 outlining new conditions for utilities to propose hosting capacity upgrade plans. These proposals would open restricted or closed circuits on the distribution system through proactive investments supported by a cost allocation and recovery method that distributes upgrade costs among current and future interconnecting customers, as well as ratepayers. Utility hosting capacity upgrade plans shall include the following, among other things:

- a description of the electric system at the feeder and substation level and the assumptions used for prioritizing the area slated for the hosting capacity upgrade
- modeling methodology and costs
- justification of the amount allocated to ratepayers
- proposed cost allocation methodology and the risks to ratepayers if the hosting capacity upgrade is not fully used by developers
- a hosting capacity fee cost cap for DER developers

Other Jurisdictions

New York has been modernizing its interconnection processes, including the DER interconnection study process under its Value of Distributed Energy Resources (VDER) initiative designed to improve the interconnection of DERs onto the distribution grid through a compensation mechanism based on the energy and non-energy values that DERs provide to the grid. Through a coordinated interconnection process, IOUs are required to proactively share granular data with developers and other stakeholders and to set dynamic hosting capacity thresholds. These dynamic thresholds reflect real-time conditions on the grid, accounting for load levels, thermal constraints, voltage limits, and other technical constraints. The thresholds set limits on the amount of DER capacity that can be added to specific grid areas without triggering grid upgrades. These dynamic thresholds reflect real-time conditions on the grid, accounting for load levels, thermal constraints, voltage limits, and other technical constraints. The thresholds set limits on the amount of DER capacity that can be added to specific grid areas without triggering grid upgrades.

Under California's Rule 21, IOUs are required to provide more granular and dynamic hosting capacity maps based on real-time data.

Cost Allocation

The serial study process can lead to unpredictable and unequal cost responsibility for DER projects. Even with hosting capacity maps and other methods to provide projects with early information on available grid capacity, project developers cannot predict whether or how many other projects will join the queue and take up available capacity before interconnection applications are completed for their own projects.

A project joining the queue for a location with sufficient capacity at the right time benefits from that available capacity without having to pay the costs to make that capacity available. In contrast, another project that happens to trigger grid upgrades must bear the cost responsibility for those upgrades. Subsequent nearby projects can utilize the upgraded grid capacity without paying for this benefit (the so-called free rider problem). The allocation of grid upgrade costs to the single project that triggers them also means that certain system substations, which require significant upgrade costs before additional DERs can be interconnected, may deter these interconnections altogether if no individual project can afford them. These upgrade costs could be manageable if shared among several interconnecting DER projects or even among the multi-beneficiaries of the grid improvements, such as the utilities, current and future DER developers, and ratepayers.

Additionally, the unpredictability of grid upgrade costs (and the lack of transparency into real-time hosting capacity) can lead developers to submit speculative interconnection applications for different locations on the utility's system while only intending to pursue interconnection at the location with the lowest interconnection costs. This dynamic means that interconnection queues can be flooded with speculative applications, requiring utilities to expend the time and resources to perform studies that will not materialize into actual projects. The bloated queue and unnecessary studies slow down the interconnection process and introduce additional uncertainty, which in turn increases the incentive for developers to submit speculative applications in the hope of securing one location with reasonable grid upgrade costs and timeline.

Several states have adopted alternative cost allocation mechanisms to make distribution system upgrade cost allocation more predictable and equitable among interconnecting projects.

Cross-Jurisdictional Comparison

The three jurisdictions take different approaches to DER interconnection cost allocation. Maryland and Massachusetts are both exploring multi-beneficiary cost-sharing frameworks where ratepayers contribute to a share of the system upgrade costs, but Maryland's approach focuses on cost recovery, whereas Massachusetts' approach addresses ratepayer-funded proactive grid investments. Illinois, on the other hand, largely uses a conservative cost-causer pays framework and allows for reimbursement by future interconnecting DER projects for the initial project that triggered and paid for the upgrade. Illinois also allows members of group studies to develop cost-sharing approaches that equitably allocate grid upgrade costs among the participating group members.

Xcel, in Appendix I of its 2023 IDP, addressed multiple cost-sharing approaches, including cost-sharing alternatives to its current cost-causation method for assigning distribution system upgrade costs. In its IDP, Xcel discussed four alternative methods:

1. Retroactive cost sharing among interconnecting DER facilities
2. Prospective, location-specific cost sharing among interconnecting DER facilities based on a per-kW upgrade cost
3. Ratepayer cost recovery for distribution system upgrades to accommodate more DERs
4. A hybrid approach splitting upgrade costs between the interconnecting facility that triggered the upgrade and surrounding utility customers and facilities benefitting from the upgrade

Xcel argued that the first two approaches would be administratively burdensome for the utility and that the fourth option would need further development. Based on Xcel's IDP and commenter filings, MPUC established a stakeholder process to develop a framework addressing cost allocation and proactive upgrades.[114] On September 26, 2024, MPUC issued a *Notice Soliciting Stakeholder Members* under Docket E002, E015, E017/CI 24-288 and formally established a DER Cost Sharing Workgroup to develop standards for distribution system cost-sharing. The stakeholder process will result in a proposed framework by July 1, 2025. Similarly, on September 26, 2024, MPUC issued an additional *Notice Soliciting Stakeholder Members* for the Proactive Grid Upgrade Workgroup, which is tasked with developing a record and a framework proposal on the cost allocation of proactive grid investments for MPUC consideration and possible adoption.

Recommendations on Cost Allocation

Through the Proactive Grid Upgrade Workgroup and the DER Cost Sharing Workgroup, Minnesota could consider a multi-beneficiary cost-sharing approach for DER interconnection, where the costs of grid upgrades are shared among multiple beneficiaries rather than solely on the project that triggered the need for the grid upgrade. This approach would result in more equitable cost allocation among all the parties benefiting from the grid upgrade and could even include an element of proactive grid upgrade

[114] Laws of Minnesota 2024, Regular Session, chapter 126, article 6, section 53. The legislature required the MPUC to initiate a proceeding by September 1, 2024, to investigate distribution upgrades and cost allocation procedures.

planning, where anticipated system investments are proactively made. One potential framework for multi-beneficiary cost-sharing is the reimbursement mechanism where the initial interconnection project that triggered the upgrade would receive reimbursement from subsequently interconnecting projects based on their percentage of capacity used. This multi-beneficiary framework would need MPUC to develop a regulatory framework with rules defining who pays, when costs are shared, and how and when reimbursements occur.

However, it is worth noting the various challenges associated with the multi-beneficiary cost-sharing approach.

Challenges arise with the multi-beneficiary approach that seeks to share grid upgrade costs with future ICs. One key issue is equitable cost allocation—how can a cost-sharing framework ensure that the initial triggering interconnection project is equitably and fairly compensated by future interconnecting projects in a timely manner? The initial triggering project will still need to pay a significant portion of the grid upgrade costs, and this upfront cost will impact the project's ability to secure financing at a reasonable rate, which ultimately will be passed on to ratepayers.

A second challenge with this multi-beneficiary cost-sharing approach relates to the timing of future interconnecting projects. If DER growth is slower than anticipated, the initial triggering project may either not get fully reimbursed or may be slow to get reimbursed. Under both scenarios, this project is exposed to financial risk.

Challenges also arise with multi-beneficiary cost-sharing that includes ratepayers. One key challenge is determining how to allocate costs between the ICs and ratepayers. Which ratepayers should be charged for grid upgrades—only ones directly benefiting from the DER projects? What about LMI ratepayers?

Another challenge could arise with multi-beneficiary cost-sharing that includes ratepayers if future DER growth falls short of what is expected. Then, ratepayers could be asked to subsidize an even larger portion of grid upgrades without recouping any of the non-energy and energy benefits that come from DERs.

These challenges should be considered, and solutions should be clarified in any regulations so that cost recovery mechanisms are equitable for the triggering project, subsequent interconnecting projects, and ratepayers.

Illinois

Illinois' cost allocation interconnection rules largely support the cost-causer-pays framework due to a reliance on the standard serial study process, where the initial project that triggered the need for the grid upgrade is burdened with the full costs of the upgrades. The rules also include a provision that enables the initial project that triggers and pays for grid upgrades to receive reimbursement from subsequent interconnecting projects that use the same upgraded infrastructure within a specified timeframe. In addition to these serial study cost allocation methods, interconnecting group projects within the same group study may determine their own cost-sharing arrangement for the costs of studies and needed grid upgrades. These options help reduce the cost burden for individual projects and instead recover the costs of grid upgrades from all interconnecting beneficiaries.

Massachusetts

Aside from the standard group study process, the Massachusetts DPU also adopted a provisional framework in 2021 that allows utilities to pursue ratepayer-funded capital investment projects (CIPs) for grid upgrades to support DER interconnections, and interconnecting customers that utilize these upgrades will then reimburse ratepayers through interconnection fees. Under this provisional framework, the state will gather data on the impacts of this cost-sharing methodology on DER deployment, particularly community solar. Under this framework, the utility first develops a CIP for upgrades identified through a group study and files the CIP with the DPU for approval. The CIP must include a description of the upgrades, associated costs and timeline, a detailed cost allocation proposal, and other relevant information. CIP upgrades must serve multiple DER facilities and must result in a cost to interconnecting customers of $500/kW or less. The utility must also show that it will interconnect the estimated DG facilities within a specified rate recovery period (e.g., 10 years) and that it can complete the construction activities within its control within 4 years from the approval date of the CIP. If the CIP is approved, the utility will construct grid upgrades and initially recover the costs for those upgrades through a Reconciling Charge assessed to all distribution customers. DG projects that interconnect to the system and benefit from the CIP upgrades will be charged CIP fees based on each facility's pro rata share of the cost of the CIP, effectively refunding ratepayers over time for the initial costs of the CIP.

The provisional CIP, as its name implies, was introduced as an interim solution to address DER interconnection cost allocation issues while the state explores more holistic and comprehensive reforms to DER interconnection. The framework has built in modification flexibility, and the DPU engages with utilities, developers, and clean energy advocates to refine the framework. Through Order 19-55 (grid modernization and interconnection reforms), the Massachusetts Department of Public Utilities is addressing comprehensive interconnection reforms, including cost allocation, through multiple dockets related to interconnection standards and the state's clean energy goals.[115] One of the cost allocation methods being explored is multi-beneficiary cost allocation—a cost-sharing approach where multiple stakeholders (e.g., utilities, current and future DER developers, and ratepayers) share the costs of grid upgrades. This ongoing work is being driven by various working groups, including the Massachusetts Technical Standards Review group and the Grid Modernization Working Group.

Maryland

In 2016, the Maryland Public Service Commission initiated Public Conference 44 aimed at modernizing the state's electric distribution grid to help the state meet its clean energy goals by interconnecting more DERs in an affordable, reliable, customer-centered, and environmentally sustainable manner. Out of the Public Conference 44 Work Group arose the Maryland Cost Allocation Model (MCAM), designed to address the causer-pay model and implement a more equitable cost allocation methodology where costs are spread among larger interconnecting customers and ratepayers (Phase III Final Report). Under the MCAM, the project that triggers grid upgrades would only have to pay for its proportional share of

[115] Massachusetts Department of Public Utilities, *Order on Grid Modernization*, DPU 19-55 (May 22, 2019). The order is a key regulation for driving DER interconnection reform to improve reliability, safety, clean energy deployment, and energy system planning. The order requires utilities to file grid modernization plans detailing plans for upgrading the grid to support increased DER penetration while improving resilience, maintaining safety, and increasing system flexibility.

the increased hosting capacity, and subsequent projects that benefit from the same increased hosting capacity would also pay for their proportional shares. The utility would first recover the costs of grid upgrades in a rate case or a regulatory asset, and payments from interconnecting customers will then be used to offset the utility's future revenue requirement. According to the Work Group, the MCAM more fairly allocates upgrade costs among all benefiting projects and enables utilities to right size grid upgrades to account for future DER interconnections (Phase IV Final Report).

Phase V is the latest set of recommendations issued by the Work Group; while the Maryland PSC has not yet adopted the recommendations from the Phase V report, the Work Group's proposed changes have further refined the MCAM and intend to make DER interconnection more cost effective, predictable, and transparent. Phase V improves MCAM's multi-beneficiary cost-sharing methodology by expanding cost allocation among multiple beneficiaries, such as future interconnecting DERs, utilities, and ratepayers. New dynamic hosting capacity calculations would allow for more real-time assessments of the need for grid upgrades and would include a hosting capacity fee for primary voltage facilities that require upgrades to enlarge hosting capacity. This hosting capacity fee would apply to future interconnecting customers and excludes costs that solely benefit the interconnecting customer that triggered the upgrade. At the secondary voltage level, for both residential and commercial interconnecting customers, hosting capacity upgrade costs are socialized either through ratepayer mechanisms or through multi-interconnecting customer cost recovery.

6.0 Conclusion

Minnesota's CSG program has played a long and significant role in providing businesses, institutions, and residents access to solar power in addition to advancing the state's clean energy goals. Since 2013, the program has deployed over 900 MW of community solar capacity, including capacity for LMI households and LMI-serving institutions.

Recent legislative changes, along with the transfer of program administration from Xcel to Commerce, seek to improve the program by enhancing its ability to reach more LMI households and deliver multiple energy and non-energy benefits to Minnesotans in a cost-effective manner.

This legislatively-directed study analyzed Minnesota's LMI-Accessible CSG Program, comparing it to other leading community solar programs from other jurisdictions. It highlights the importance of addressing program challenges such as removing interconnection barriers, improving consumer protections, eliminating low-income application barriers, and optimizing cost-efficiency. The report recommends adopting best practices from other jurisdictions, improving income verification processes, developing marketing guidelines and compliance monitoring systems, and adopting practices that lead to a more transparent, LMI-accessible, and consumer-friendly program.

This report also provides detailed cost-effectiveness analyses of the CSG program's expected impacts on ratepayers and society at large; the analyses include consideration of alternatives to the current LMI-Accessible CSG Program such as adjustments to subscription fees, variability in annual installed CSG capacity, and an alternative solar procurement mechanism. The findings of the analyses highlight the potential cost savings for LMI subscribers and the financial implications for non-program participants as CSG capacity grows. These potential financial benefits are highly dependent on subscription fees.

Finally, the BCA results also suggest that LMI subscribers would experience more significant bill savings if they did not have to pay above-market CSG program costs through the fuel surcharge. The report authors recommend that the state consider extending the CSG statute protection to LMI subscribers (vs. just non-program participants).

Lastly, the report suggests that Minnesota may wish to consider adopting new interconnection practices that are better aligned with an ever-increasing demand for community solar gardens and distributed clean energy deployment. Highlights from the set of interconnection recommendations include adopting more flexible interconnection processes that maximize the use of available distribution capacity and considering a multi-beneficiary cost-sharing approach for any necessary grid upgrades. These innovations could result in increased DER interconnection, a more reliable grid, and a more equitable approach to distributing interconnection costs.

Minnesota can continue leading the nation with an impactful and innovative CSG program that extends clean energy and environmental benefits equitably. As the LMI-Accessible CSG Program develops and continues to innovate, it can ensure long-term equitable solar deployment by carefully balancing benefits and costs, ensuring accessible LMI participation, and adopting innovative, dynamic, and flexible interconnection practices.

Appendix A: Summary of Key Regulatory Proceedings

Appendix A offers additional detail regarding the major MPUC filings summarized in Section 2.2 of the report. The proceedings summarized below and in the report are those with CSG program implications since the Legacy program's inception in 2013. The summaries focus on Orders, which take into account the regulatory record for that proceeding, but some key filings from parties are also summarized where appropriate. Proceedings summarized in Appendix A are listed below.

- Docket No. E002/M-13-867: *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*
- Docket No. E002/CI-23-335: *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*
- Docket No. E-999/M-14-65: *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f)*
- Docket No. E002/M-21-695: *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*
- Docket No. E999/CO-16-521: *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*
- Docket No. E-002/M-23-452: *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*
- *Docket No. E002,E015,E017/CI-24-288: In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*
- Docket No. E002,E015,E017/CI-24-318: *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy*

Docket No. E002/M-13-867: In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program

In response to the requirement established under the Legacy program, Xcel submitted its Initial Petition requesting approval of its CSG program tariff filing on September 30, 2013.[116] Xcel's initial proposal was subject to an extensive public review period and was eventually rejected by MPUC on April 7, 2014, at which time MPUC directed Xcel to file a revised proposal. In its April 7th Order, MPUC directed Xcel to file a value-of-solar (VOS) tariff consistent with Commerce's methodology that MPUC approved with modification on April 1, 2014 (Docket No. 14-65), or to provide calculations demonstrating why such a rate should not be used.[117]

[116] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Petition: Community Solar Gardens Program (September 30, 2013).

[117] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Rejecting Xcel's Solar Garden Tariff Filing and Requiring the Company to File a Revised Solar-Garden Plan (April 7, 2014).

Xcel submitted a revised CSG tariff filing in May 2014.[118] Following comments on Xcel's revised filing, MPUC issued a September 17, 2014, Order approving the revised plan, with modifications.[119] In MPUC's September 17 Order, MPUC concluded that at that time, the use of the VOS rate (as calculated using the approved Department-developed methodology) was not in the public interest. Accordingly, MPUC directed Xcel to continue using the Applicable Retail Rate (ARR), but also requested that parties continue to file comments to help identify what, if any, cost adder could be applied in combination with the proposed VOS rate to ensure statutory compliance. The Order also directed Xcel to file annual VOS inflation updates and updated rate calculations, in addition to other plan revisions and compliance filing requirements. Xcel submitted its revised compliance filing (with MPUC's requested modifications incorporated) on September 29, 2014.[120]

On October 7, 2014, TruNorth Solar filed a request for clarification regarding the definition of a solar garden *subscriber* per MPUC's September 17th Order. TruNorth's request sought clarity regarding whether—under Xcel's approved CSG program—a "customer" or "subscriber" was intended to refer to an individual service address. Notably, situations could occur in which a single customer (e.g., a school district with five schools, each using 1 MW of electricity) could offset the entire district's electricity needs without violating the 40% rule.[121] MPUC issued a comment period to hear parties' perspectives, and on February 13, 2015, denied TruNorth Solar's request for clarification on this item, instead directing Xcel Energy to provide clear information on the Company's website regarding what constitutes a subscriber under the CSG program.[122]

On March 13, 2015, MPUC issued a notice requesting comments regarding, "whether and when there should be a transfer from the ARR to the VOS for the CSG bill credit and whether an adder is necessary to provide a rate that will reasonably allow for the creation, financing, and accessibility of solar gardens."[123]

On April 28, 2015, Xcel filed supplemental comments regarding program administration, specifically with respect to co-location of CSG facilities. The Legacy program capped individual projects at 1 MW, but neither the statute nor the Commission had addressed the co-location of several 1 MW facilities which—in aggregation—add up to more than 1 MW. In its filing, Xcel proposed a revised program

[118] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Compliance Filing, (May 7, 2014).

[119] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Solar Garden Plan with Modifications, (September 17, 2014).

[120] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Compliance Filing (revised), (September 29, 2014).

[121] The "40% rule" under the Legacy program established that "the community solar garden program must be designed to offset the energy use of not less than five subscribers in each community solar garden facility of which no single subscriber has more than a 40 percent interest." (Minnesota Statute § 216B.1641, Subd. 1)

[122] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Denying Request for Clarification and Setting Public Information Requirements (February 13, 2015).

[123] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Notice of Comment Period (March 13, 2015).

implementation strategy, stating that, “all existing or new applications which propose co-located gardens with an aggregate capacity greater than 1 MW will be scaled to 1 MW.” Xcel did not state that they would not process applications for co-located facilities, but rather established that they would only process applications for co-located facilities if the aggregate capacity of those facilities together was no larger than 1 MW.[124]

On May 1, 2015, MPUC issued a Notice requesting feedback on Xcel’s proposed strategies to address co-location challenges, as well as “identification of all issues that require Commission action,” related to Xcel’s CSG program. [125] On the same day, Commerce issued a motion requesting MPUC issue an Order to Show Cause; in Commerce’s motion, it requested that MPUC direct Xcel to demonstrate why MPUC should *not* 1) find Xcel’s proposed co-location strategy to be in violation of existing orders, and 2) order Xcel to continue processing co-located facilities that in aggregate are larger than 1 MW.[126] A public comment period with substantial feedback followed. Additionally, Xcel filed a Request for Investigation into Prospective Program Design on July 24, 2015, following a June 22 partial settlement agreement on the issue, signed by Xcel and other parties.[127] In Xcel’s request, it asked that the Commission open an investigation on the matter to address several outstanding questions, including questions pertaining to facility co-location, via a contested case under the Office of Administrative Hearings. MPUC denied Xcel’s request in an Order dated November 16, 2015.[128]

MPUC issued an Order on August 6, 2015, adopting the partial settlement agreement, with specific modifications related to the interconnection process and program administration. In the Order, MPUC established that CSG applications in the interconnection queue as of the date the Order became effective, which are proposed with no more than 5 MW of aggregate capacity, would be allowed. The Order also directed Xcel to reduce co-located facilities in the queue with aggregated capacity in excess of 5 MW down to this 5 MW limit. The Order also defined “co-location”, stating that co-located CSG facilities were facilities that, “exhibit characteristics of a single development including, but not limited

[124] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Supplemental Comments and Notice to Administer Program Consistent with CSG Statute (April 28, 2015).

[125] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Notice of Comment Period (May 1, 2015).

[126] Minnesota Department of Commerce, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Motion for an Order to Show Cause (May 1, 2015).

[127] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Prospective program Design – Investigation (July 24, 2015).

Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Partial Settlement Agreement (June 22, 2015).

[128] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Denying Petition for Contested Case and Establishing Procedures for Further Comments (November 16, 2015).

to, common ownership structure, an umbrella sale arrangement, shared interconnection, revenue-sharing arrangements, and common debt and equity financing."[129]

For several years following these initial Orders, which helped clarify aspects of the Legacy statute in the program's early stages, Xcel continued submitting annual CSG tariff filings in this proceeding for MPUC review and approval. During this time, MPUC continued seeking feedback regarding whether they should adopt Commerce's VOS methodology for use to determine CSG bill credits. On September 6, 2016, MPUC issued an Order approving VOS for use as a bill credit rate for all CSG applications filed after December 31, 2016. MPUC directed Xcel Energy to make changes to its CSG tariff accordingly, which Xcel later submitted for review. MPUC also directed Xcel to develop a CSG program proposal specific to low-income customers. Additionally, MPUC directed Commerce to evaluate whether the VOS bill credit rate should be adjusted with a positive or negative cost adder for the following factors, to be provided to MPUC as a report by March 1, 2017:[130]

- Brownfield sites or landfills
- Public facilities
- Commercial or industrial rooftops
- Prime agricultural land
- Directly in the communities where the solar gardens serve
- Residential subscribers
- Low-income residential subscribers
- Others Commerce identifies as warranting modification or an adder.

On March 1, 2017, Commerce submitted comments in response to MPUC's Order, taking into consideration feedback received from interested parties. In its report, Commerce recommended that MPUC adopt adders (positive or negative) for CSG facilities sited on brownfield locations, prime agricultural land, rooftops and/or areas close to customer load, and public facilities. Additionally, Commerce recommended that MPUC, "revisit consideration of an adder specific to low-income subscribers when Xcel's low-income CSG proposal has been developed."[131] In response to Commerce's recommendations, MPUC issued an Order on December 14, 2017, directing Xcel to file an analysis of potential rate impacts of various levels of residential solar garden penetration in accordance with

[129] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Adopting Partial Settlement as Modified (August 6, 2015).

[130] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Value-of-Solar Rate for Xcel's Solar Garden Program, Clarifying Program Parameters, and Requiring Further Filings (September 6, 2016).

[131] Minnesota Department of Commerce, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Comments of the Minnesota Department of Commerce, Division of Energy Resources (March 1, 2017).

Commerce's filing, and an analysis of how a residential solar carve-out would be implemented and enforced.[132]

Xcel submitted its analysis in response to this Order on February 1, 2018, which was followed by a public review period.[133] On November 16, 2018, MPUC issued an Order approving Xcel's proposed cost adder approach in response to Commerce's earlier recommendations, and on October 7, 2021, MPUC issued an Order extending the adder for an additional two years. [134] In this Order, MPUC directed Xcel to prepare an evaluation report documenting CSG project and subscription data, including data pertaining to subscriber class and the total number of CSG program participants who also participate in the Low Income Home Energy Assistance program (LIHEAP).[135]

On August 2, 2019, Xcel submitted a proposed modification to the VOS methodology, intended to address identified volatility in the calculation outcome.[136] This is described in greater detail below in the Docket No. E999/M-14-65 summary. Following public comments on Xcel's proposed modifications, MPUC approved the changes in a December 3, 2019, Order and established some additional requirements for annual VOS update filings in an additional Order issued March 4, 2020.[137]

On September 23, 2021, Xcel filed joint comments with Energy CENTS Coalition, Mid-Minnesota Legal Aid, and the Citizens Utility Board of Minnesota, seeking approval for proposed CSG tariff modifications that intended to establish consumer protections for tenants residing in rental properties, where the rental property is a CSG subscriber. The proposal intended to improve consumer protections for CSG

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[132] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Requiring Further Analysis of Residential Adders and Carve-Outs (December 14, 2017).

Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Notice of Required Filing (December 1, 2017).

[133] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Value of Solar Adders Analyses (February 1, 2018).

Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Value of Solar Adders Analyses–corrected (February 23, 2018).

[134] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Adopting Adder and Setting Reporting Requirements (November 16, 2018).

[135] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Extending the Residential Adder and Requiring Additional Filings (October 7, 2021).

[136] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Petition: Value of Solar Methodology (August 2, 2019).

[137] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Changes to Distributed Solar Value Methodology as Modified and Requiring Further Filings (December 3, 2019).

Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Xcel's Update to the 2020 Value of Solar Rate (March 4, 2020).

subscribers, including ensuring low-income program eligibility.[138] The joint commenters cross-filed this proposal in Docket No. 21-695, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility. This filing and related contributions to the record in that proceeding are described in greater detail below in a section dedicated to Docket No. 21-695.

In a June 24, 2022, Order, MPUC declined to approve the proposal, but directed Xcel to otherwise modify its tariffs to address some concerns, and also directed that a stakeholder process be established to identify solutions to these issues.[139] On September 1, 2022, Xcel filed its proposed 2023 VOS calculation update.[140] MPUC approved Xcel's proposed update on April 6, 2023, with modifications.[141] Specifically, MPUC directed Xcel to work with Commerce and interested stakeholders to identify possible adders including an income-qualified adder.

On July 26, 2023, MPUC issued a Notice of Comment Period seeking to understand the actions the Commission should take in response to the 2023 legislative updates to the CSG program, which were passed that Spring session and set to go into effect on January 1, 2024.[142] Materials relevant to the new LMI-Accessible CSG program are cross-filed in both Docket No. 13-867 (this proceeding) and Docket No. 23-335, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, which is summarized below.

On February 23, 2024, MPUC issued an Order discontinuing the requirement that Xcel submit annual VOS compliance filing in response to Xcel's 2024 VOS compliance filing (filed on September 1, 2023), and subsequent comment periods. In the Order, MPUC stated that, "the actual uses for the VOS remain unclear, and requiring annual updates necessitates additional proceedings that expend valuable stakeholder and Commission time. The Commission concludes that the need to preserve scarce regulatory resources outweighs the possible future usefulness of VOS annual filings."[143]

In this Order, the Commission established that Legacy CSG facilities (i.e., facilities approved before January 1, 2024) will continue to utilize the VOS bill credit, but that new CSG facilities subject to the LMI-Accessible CSG program would instead be subject to new program parameters. Commerce and other

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[138] Xcel Energy, Energy CENTS Coalition, Mid-Minnesota Legal Aid, and Citizens Utility Board of Minnesota, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Petition (September 23, 2021).

[139] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Denying Petition Addressing Low-Income Energy Assistance Programs, and Requiring Further Proceedings (March 4, 2020).

[140] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, 2023 VOS Calculation (September 1, 2022).

[141] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Value of Solar Rate and Setting Additional Requirements (April 6, 2023).

[142] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Notice of Comment Period (July 26, 2023).

[143] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Docket No. E-002/M-13-867, Order Discontinuing Value-of-Solar Filing Requirement (February 23, 2024).

parties had advocated that the annual VOS filing requirement remain, as it provides valuable data about distributed solar resources in Minnesota. However, MPUC's Order established that Xcel is no longer obligated to submit such a filing.

On May 30, 2024, MPUC issued two orders in this proceeding:[144]

- *Order implementing new legislation governing community solar gardens*, and
- *Order approving community solar garden program rate-transition proposal with modifications*

In the first of these two orders (which was cross-filed in Docket No. E002/CI-23-335), MPUC provided clarification regarding CSG program implementation considerations including Xcel's use of their online portal for applications, as described in greater detail under the Docket No. E002/CI-23-335 summary. In the second order, MPUC approved Xcel's September 25, 2023, compliance filing (as modified),[145] which proposed to switch CSG subscriptions that fall under the ARR credit to the VOS rate.

In June 2024, multiple parties filed petitions for reconsideration of MPUC's second May 30 Order, including a request for rehearing filed jointly by several solar developers and developer associations. These petitions largely focused on the appropriateness of transitioning from the VOS tariff to the ARR for CSG subscriptions, requesting that MPUC reject Xcel's proposal to switch these subscriptions from the ARR credit to the VOS rate.[146]

On August 1, 2024, MPUC held a meeting in response to the petitioners' requests for reconsideration and a rehearing. At this meeting—and as described in the subsequent Order issued on August 16, 2024—MPUC denied the petitioners' requests for a rehearing.[147] In August and September 2024, these same joint petitioners and others filed additional Applications for Rehearing in response to MPUC's August 16 Order, seeking to ensure that parties preserved their ability to challenge the May 30 Order in question on appeal.[148] On October 10, 2024, MPUC held a hearing to discuss whether to reconsider its August 16 Order denying the petitions, grant reconsideration of the August 16 Order, and/or stay

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[144] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Implementing Legislation Governing Community Solar Gardens (May 30, 2024).

Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Approving Community Solar Garden Program Rate-Transition Proposal with Modifications (May 30, 2024).

[145] Xcel Energy, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Proposal for Switching ARR-era Community Solar Gardens to Appropriate VOS Rate (September 25, 2023).

[146] CCSA, MnSEIA, Cooperative Energy Futures, PureSky Community Solar, Inc., SunShare, LLC, BHE Renewables, and Cypress Creek Renewables, LLC. In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Joint Application for Rehearing (June 20, 2024).

[147] Minnesota Public Utilities Commission, In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Order Denying Requests for Reconsideration of May 30, 2024 (August 16, 2024).

[148] CCSA, MnSEIA, Cooperative Energy Futures, PureSky Community Solar, Inc., SunShare, LLC, BHE Renewables, and Cypress Creek Renewables, LLC. In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Docket No. E-002/M-13-867, Joint Application for Rehearing (September 5, 2024).

implementation of this May 30 Order. At the hearing, MPUC declined the request to reconsider its August 16 decisions.

Docket No. E002/CI-23-335: In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program

On July 26, 2023, MPUC opened a new docket (Docket No. 23-335) dedicated to the implementation of the LMI-Accessible CSG Program.[149] In opening the proceeding, MPUC sought public feedback and comments on questions and topics pertaining to the transition from the Legacy program, compensation under the new program, and billing requirements.

Following an extensive comment period, MPUC issued an Order on December 28, 2023, in which it implemented the new LMI-Accessible CSG legislation established in Minnesota Statute § 216B.1641. In summary, MPUC's Order establishes the following with respect to the new program, though this list does not comprehensively describe all aspects of the Commission's Order. For exact language, please refer directly to the Order.[150]

- "Approved" CSG projects, as referenced in Subd. 1(i), are projects with applications that have been deemed complete before January 1, 2024. Projects deemed complete before that date remain subject to the Legacy program.
- Xcel must implement consolidated billing by January 1, 2025, as described in Subd. 10(c), and must begin submitting quarterly filings on its consolidating billing program status starting on June 1, 2024.
- Xcel may assess the following annual fees:
    - $500 per MW for CSGs in the Legacy and LMI-Accessible CSG programs
    - $4,125 per MW application fee for LMI-Accessible CSG program implementation costs, with opportunity for refund following a comment period
- With respect to nonsubscriber protections from fuel adjustment charges, established under Subd. 11
    - Xcel may focus on customers that have participated in bill payment assistance or income-qualified energy efficiency programs within the preceding twelve months when identifying customers who qualify for exemption of certain CSG costs
    - Xcel must work with Commerce to identify low-income customers eligible for this exemption
    - Xcel's proposed methodology for determining and applying the net cost of generation for CSGs meets statutory requirements
- Xcel may retain ownership of RECs generated by the LMI-Accessible CSG program
- Xcel must submit annual proposed changes to its LMI-Accessible CSG Program Retail Rate.

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[149] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Notice of Comment Period (July 26, 2023).

[150] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Order Implementing New Legislation Governing Community Solar Gardens (July 26, 2023).

- Xcel must submit an updated tariff filing within 30 days of MPUC's December 28, 2024, Order.

In response to this Order, Xcel submitted their annual tariff filing on January 5, 2024, following a letter filed on January 2, 2024.[151] Several parties, including Commerce, objected to Xcel's tariff filing and expressed that the process through which Xcel proposed to collect the application fee (at the start of the interconnection application process) violated the Minnesota Distributed Energy Resources Interconnection Process (MN DIP).[152] On February 5, 2024, MPUC issued a Notice of Comment Period seeking to determine if Xcel's January 5th filing was consistent with MPUC's December 28, 2023 Order.[153] In that comment period, stakeholders identified five issues with Xcel's filing, which MPUC outlined as the following unresolved questions in a May 30, 2024 MPUC Order:[154]

1. May Xcel require non-legacy program applicants to file their interconnection agreements through a different portal than the one used for all other distributed generation projects?
2. May Xcel charge the approved $4,125/MW program application fee at the start of the application process?
3. Must there be a contract or Power Purchase Agreement (PPA) in place between Xcel and non-legacy CSG project operators?
4. Must Xcel track and pay bill credits if it does not have IT systems in place to support the bill credit functionality?
5. Must Xcel allow a CSG to maintain its queue position if the CSG requests to switch programs?

In issuing the May 30, 2024, Order, MPUC aimed to resolve these outstanding issues. With respect to stakeholders' concerns expressed regarding the interconnection application payment timeline, MPUC established that the fee would only be required after Commerce approved a project to participate in the CSG program.

Docket No. E999/M-14-65: In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f)

On January 31, 2014, Commerce filed their proposed Minnesota Value of Solar (VOS) Methodology for MPUC review, as required under Subd. 1(d) of the Legacy statute. Commerce developed its proposed methodology in collaboration with stakeholders.

In response to Commerce's filing, MPUC immediately issued a Notice of Expedited Comment Period on Commerce's proposed VOS methodology filing. MPUC sought comments on whether the proposed

[151] Xcel Energy, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Compliance Filing – Tariffs (January 5, 2024).

[152] Coalition for Community Solar Access (CCSA), *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Letter of Objection (January 25, 2024).

[153] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Notice of Comment Period (February 5, 2024)

[154] Minnesota Public Utilities Commission, *In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program*, Docket No. E002/CI-23-335, Order Implementing New Legislation Governing Community Solar Gardens (May 30, 2024).

methodology met statutory requirements and presented a reasonable approach.[155] On April 1, 2024, MPUC issued an Order approving Commerce's proposed VOS methodology (inclusive of revisions Commerce offered in their February 20, 2014 reply comments), with modifications pertaining to the fuel price escalation factor, avoided distribution capacity cost, and the non-CO_2 avoided environmental cost values.[156]

With MPUC's approval of the VOS methodology, MPUC also established that utilities filing a CSG tariff in accordance with Minnesota Statute § 216B.164, Subd 10 must utilize the approved methodology, effective immediately. Following this Order, Xcel submitted annual VOS tariff filings in the general CSG proceeding (Docket No. 13-867), taking yearly variations such as inflation into account. In subsequent years, MPUC made some changes to the VOS methodology via Orders in the general CSG proceeding, where Xcel submitted regular compliance filings.

On August 2, 2019, in Docket No. 14-65, Xcel filed a proposed modification to the approved VOS methodology, arguing that over time, the VOS methodology had resulted in rates that are "unreasonable, unrepresentative, and [that] clearly [fall] outside of the public interest."[157] MPUC sought public comments on Xcel's proposal; comments received were generally supportive of the proposed changes, with some specific additional recommendations pertaining to the methodology. On December 3, 2019, MPUC approved Xcel's proposed changes to the VOS methodology, with some modifications.[158]

With the updated CSG legislation, MPUC found a need to clarify the role, if any, of VOS under the new LMI-Accessible CSG program, which has different bill credit compensation specifications than the Legacy program and which specifically directed the use of a Department-developed VOS methodology. MPUC directed filings and deliberations related to the future use of VOS under the new program to the general CSG proceeding and the proceeding focused on implementing the new program (Dockets No. 13-867 and 23-335, respectively).

Potential ratepayer implications related to VOS and the LMI-Accessible CSG program in general are discussed in greater detail in Section 4.0, *CSG Program Ratepayer Impacts*, of this report.

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[155] Minnesota Public Utilities Commission, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f), Docket No. E-999/M-14-65, Notice of Expedited Comment Period on Distributed Solar Value Methodology Proposal (January 31, 2014).

[156] Minnesota Public Utilities Commission, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f), Docket No. E-999/M-14-65, Order Approving Distributed Solar Value Methodology (April 1, 2014).

Minnesota Department of Commerce, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f), Docket No. E-999/M-14-65, Reply Comments of the Minnesota Department of Commerce, Division of Energy Resources (February 20, 2014).

[157] Xcel Energy, *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f),* Docket No. E-999/M-14-65, Petition – Value of Solar Methodology (August 2, 2019).

[158] Minnesota Public Utilities Commission, *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f),* Docket No. E-999/M-14-65, Order Approving Changes to Distributed Solar Value Methodology as Modified and Requiring Further Filings (December 3, 2019).

Docket No. E002/M-21-695: In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility

As described above in the summary of Docket No. 13-867, Xcel filed joint comments with Energy CENTS Coalition, Mid-Minnesota Legal Aid, and the Citizens Utility Board of Minnesota on September 23, 2021. In this filing, Xcel sought approval for proposed CSG tariff modifications that intended to establish consumer protections for tenants residing in rental properties, where the rental property is a CSG subscriber.

In their comments, the joint parties state that with the proposed modifications, "more tenants will retain essential regulatory consumer protections provided by the Cold Weather Rule, protection from disconnection of service, and maintain the ability to qualify for the maximum LIHEAP benefit and supplemental utility affordability programs," while, "[preventing] landlords from coercing tenants to enter into CSG subscriptions as a condition of leasing a premise." Additionally, the proposal aimed to address situations in which, "tenants of multi-unit buildings [had] their accounts transferred to the building owner/landlord's name, altering the customer of record so that the building owner can subscribe to a CSG and receive the associated CSG bill credits."[159]

In a June 24, 2022, Order, MPUC declined to approve the proposal, but directed Xcel to, "propose a modification to its tariffs… to allow low-income renters who are subject to third-party billing to access [specified low-income] programs."[160] In the Order, MPUC also directed Xcel to convene a stakeholder process focused on addressing these consumer protection issues. Specifically, MPUC directed Xcel to do the following to address identified concerns via the Order.

> *2. Regarding its PowerOn Program, Medical Affordability Program, Gas Affordability Program, and Low-Income Discount Program, Xcel shall do the following:*
>
> > *A. Before Xcel transfers a utility account from a tenant to the landlord as part of a Community Solar Program, Xcel shall take reasonable steps with the landlord to help qualified tenants continue receiving the benefits of these low-income affordability programs.*
> >
> > *B. Xcel shall propose a modification to its tariffs for these programs to allow low-income renters who are subject to third-party billing to access these programs.*
>
> *4. Xcel shall work with the Energy CENTS Coalition to notify affected tenants that they may contact the Consumer Division of the OAG for information and possible assistance.*

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[159] Xcel Energy, *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*, Docket No. E002/M-21-695, Joint Petition and Proposed Tariff Modifications (September 23, 2021).

[160] Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*, Docket No. E-002/M-21-695, Order Denying Petition, Addressing Low-Income Energy Assistance Programs, and Requiring Further Proceedings (June 24, 2022).

6. Xcel shall convene a stakeholder process to further discuss the issues in these dockets within 60 days, and file revised tariffs within 120 days in this docket. The stakeholder process shall address the following issues, among others:

> *A. Transparency about Community Solar Garden offerings serving their residential unit under third-party billing systems.*
>
> *B. Tenant rights under third-party billing systems, including any right to claim control over the utility account.*
>
> *C. Low-income tenant access to utility energy assistance programs such as PowerOn even when receiving service under a third-party billing system.*
>
> *D. Ensuring that a landlord who has tenant accounts in the landlord's name may continue to participate in Xcel's CSG program, assuming the implementation of this model does not cause more harm than benefit to the tenants.*
>
> *E. Ensuring that any penalties to CSG developers who violate Xcel's tariff are based on developer-caused violations or known omissions and are commensurate with the timeframe of the violation/known omission.*

In the June 24, 2022, Order, MPUC also established internal directives to further develop the record regarding the issue and to advance awareness, and to notify the Office of the Attorney General's Consumer Protection Division of the issues identified in the joint commenters' proposal.

On November 11, 2022, Xcel submitted its filing in response to MPUC's June 24, 2022, Order. The filing included a proposed tariff that was revised to include tenant protection considerations and included documentation of the engagement process Xcel convened to find solutions to these issues.[161] Following public review, MPUC approved Xcel's filing on August 11, 2023, with minor modifications; at this point in time, the LMI-Accessible CSG legislation had been passed.

In approving Xcel's proposal, MPUC therefore established that, "Xcel must work with Commerce of Commerce's Energy Development Office on programmatic improvements to its billing system to accomplish the goals of Community Solar Garden legislation passed in the 2023 legislative session, and the goals previously set forth in ordering paragraph 2B of the Commission's June 24, 2022, Order. Before implementing changes, Xcel shall report back to the Commission no later than January 15, 2024, on details, including but not limited to: the necessary changes to its billing system, the incremental costs thereof, an analysis of what data sharing requirements will be necessary, and the estimated number of tenants/households that would benefit."[162]

In this Order, MPUC also re-opened Order Point 2B from MPUC's June 24th filing (2B: *Regarding its PowerOn Program, Medical Affordability Program, Gas Affordability Program, and Low-Income Discount*

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[161] Xcel Energy, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E002/M-21-695, Compliance Filing (November 11, 2022).

[162] Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility*, Docket No. E-002/M-21-695, Order Approving Compliance Filing and proposed Contract and Tariff Revisions (June 24, 2022).

Program, Xcel shall… propose a modification to its tariffs for these programs to allow low-income renters who are subject to third-party billing to access these programs) for continued work with Commerce.

On January 16, 2024, Xcel submitted their compliance filing documenting their engagement with Commerce consistent with the August 11, 2023 Order.[163] Commerce submitted a filing recommending the MPUC approve Xcel's filing on March 8, 2024.[164] However, on March 8, stakeholders who were part of the joint commenters who submitted the initial filing in this proceeding on September 23, 2021 (Energy CENTS Coalition, Mid-Minnesota Legal Aid, and the Citizens Utility Board of Minnesota) also provided feedback. [165]

After reviewing the comments from these stakeholders, Commerce submitted an additional filing on March 21, 2023, recommending that MPUC approve Xcel's filing with modification, including modifications proposed by Energy CENTS Coalition as well as additional modifications to the Landlord Addendum included in Energy CENTS Coalition's comments.[166] In their filing, Energy CENTS Coalition recommended that MPUC consider the following:

1. Approve Xcel Energy's Compliance Filing and the proposed changes to PowerON participant bills to reflect the affordable payment amount.
2. Approve, with [Energy CENTS Coalition's] recommended changes to the [Solar*Rewards Community] tariff… Xcel Energy's In Care of Billing Proposal
3. Require Xcel to file the [Solar*Rewards Community] tariff changes and to establish the effective date of those changes within 30 days of the Commission's Order in this matter

In a comment filed jointly by Xcel and Energy CENTS Coalition on March 22, 2024, they stated that they felt that Xcel's initial In Care of Billing proposal (with modifications by Energy CENTS Coalition incorporated) was now inconsistent with the LMI-Accessible CSG program. Accordingly, the joint parties suggested that In Care of Billing proposal (inclusive of Energy CENTS Coalition's edits) be withdrawn,

[163] Xcel Energy, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E002/M-21-695, Compliance Filing (January 16, 2023).

[164] Minnesota Department of Commerce, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Comments of the Minnesota Department of Commerce (March 8, 2024).

[165] Energy CENTS Coalition, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Comments of the Energy CENTS Coalition (March 8, 2024).

Mid-Minnesota Legal Aid, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Comments of Mid-Minnesota Legal Aid and Service Advocacy Project Regarding Xcel Energy's Compliance Filing of January 16, 2024 (March 8, 2024).

Mid-Minnesota Legal Aid, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Initial Comments of the Citizens Utility Board of Minnesota (March 8, 2024).

[166] Minnesota Department of Commerce, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Comments of the Minnesota Department of Commerce (March 21, 2024).

instead suggesting that MPUC, "evaluate the effectiveness of the current tariff opt-in and opt-out provisions."[167]

On August 27, 2024, MPUC issued a Notice of Supplemental Comment Period seeking stakeholder feedback on this matter.[168] MPUC issued a Notice of Supplemental Comment Period seeking further input from interested parties on potential actions in response to the identified issues. In their comments, Commerce noted that an opt-in/opt-out model offers improved control for tenants but also presented a situation in which tenants would need to choose between eligibility for energy assistance programs and participation in such programs. Commerce encouraged Xcel to further explore possible solutions to identified issues.[169] Other parties also emphasized the need for MPUC to continue to work toward solutions. Xcel's response comments and parties' reply comments are due by late October and early November 2024, respectively.

Docket No. E999/CO-16-521: In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611

On June 21, 2016, MPUC opened Docket No. E999/CO-16-521 to explore and update the 2004 Minnesota Standards for Interconnection of Distributed Generation.[170] Following a substantial public review period, which included a technical conference on the matter, MPUC issued an order on January 24, 2017 establishing a workgroup focused on updating and improving the state's distributed resource interconnection standards. This order directed that the 2004 standards should be updated to a format that is consistent with the Federal Energy Regulatory Commission's Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA).[171] In December of that year, MPUC issued an additional notice further directing the workgroup's scope, directing them to update Minnesota's technical interconnection requirements included in the Minnesota DG Technical Interconnection and Interoperability Requirements (TIIR) .[172]

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[167] Xcel Energy and Energy CENTS Coalition, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Joint Comments of Xcel Energy and Energy CENTS Coalition (March 22, 2024).

[168] Minnesota Public Utilities Commission, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Notice of Supplemental Comment Period (August 27, 2024).

[169] Minnesota Department of Commerce, In the Matter of Xcel Energy's Tariff Revisions Updating Community Solar Garden Tariff Providing Additional Customer Protections in Subscription Eligibility, Docket No. E-002/M-21-695, Comments of the Minnesota Department of Commerce, Division of Energy Resources (October 2, 2024).

[170] Minnesota Public Utilities Commission, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611, Docket No. E999/CO-16-521, *Notice of New Docket Number, Comment Period, and Technical Conference* (June 21, 2016).

[171] Minnesota Public Utilities Commission, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611, Docket No. E999/CO-16-521, Order Establishing Workgroup and Process to Update and Improve State Interconnection Standards (January 24, 2017).

[172] *Minnesota Public Utilities Commission, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Notice of Comment Period (December 15, 2017).

Workgroup participants included utilities, solar developers, clean energy advocacy organizations, consumer advocacy groups, industry associations, and Commerce. The workgroup consisted of Phase I (focused on updates to Minnesota's interconnection procedures), and Phase II (focused on updates to technical requirements) which occurred concurrently. Following the extensive working group effort, MPUC issued an Order adopting an updated interconnection process and an updated standard interconnection agreement on August 13, 2018.[173]

In the August 2018 order, MPUC officially adopted the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) and the Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA). The order also established a dedicated Distributed Generation Workgroup, which was directed to meet at least annually (or more frequently as needed) to discuss and address any MN DIP and/or MN DIA implementation issues that may arise.

Since that order, MPUC has directed several items to the Distributed Generation Workgroup (including to various subgroups), and Minnesota's interconnection standards have undergone several updates and revisions subject to MPUC approval. This included a directive that a technical subgroup explore the market readiness of advanced inverters meeting the IEEE 1547-2018 standard; this subgroup's efforts helped contribute to the updated TIIR, which MPUC approved on January 22, 2020 and authorized full implementation of starting in October 2023.[174] The workgroup also helped identify areas of potential transparency improvements; notably, in April 2023, MPUC issued an order requiring that until at least 2026, regulated utilities must file annual reports documenting all DER interconnections that occurred in the prior calendar year, including information related to capacity, technology types, timelines, study processes, and more.[175]

In Spring 2023, the Minnesota State Legislature passed a provision in HF 2310 (the Omnibus bill), which was incorporated under (Minnesota Law 2023, Chapter 60, Article 12, §75) directing MPUC to open a proceeding to establish customer-sited DG up to 40 kW to be processed in accordance with the MN DIP schedules and procedures. On September 1, 2023, MPUC issued a Notice for Comment seeking feedback

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[173] Minnesota Public Utilities Commission, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611, Docket No. E999/CO-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018).

[174] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Order Establishing Updated Technical Interconnection and Interoperability Requirements (January 22, 2020).

Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Notice of "Readily Available" Advanced Inverters and Full Implementation of Technical Interconnection and Interoperability Requirements (October 6, 2023).

[175] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Order Conditionally Adopting Amended Technical Interconnection and Interoperability Requirements and requiring Filings (April 11, 2023).

on what changes to MN DIP should be considered to enable this.[176] Utilities, industry associations, developers, Commerce, and other organizations filed comments and proposals in response to MPUC's request. On April 15, 2024, MPUC issued an order with consideration for this feedback. This new order directed several immediate actions, including the following directives (among others):[177]

- Xcel must operate two administrative interconnection queues (an MN DIP variance)—one queue is to be based on geographic considerations (e.g., feeder, substation) and the other is a priority queue for small customer-sited interconnection applications (i.e., no more than 40 kW)
- Xcel must include additional information in their quarterly and annual interconnection filings, including information related to small and large DER applications
- MPUC Executive Secretary must issue notice seeking feedback on reserving system capacity for small DERs
- The Distributed Generation Workgroup must explore whether battery storage systems should be evaluated under the MN DIP framework.

In May 2024, Xcel submitted an updated tariff that adopts the two-queue approach and the MPUC Executive Secretary opened a new proceeding where the system capacity topic is currently being discussed. Docket No. E999/CO-16-521 remains an active venue for discussion regarding interconnection procedures in Minnesota.

Docket No. E-002/M-23-452: In the Matter of Xcel Energy's 2023 Integrated Distribution Plan

Each of Minnesota's rate-regulated utilities must file an "integrated distribution system plan" (IDP) with MPUC every other year. The plans must include data related to the utility's distribution system, including data related to DERs, long-term distribution system planning, the use of non-wires alternatives, and financial data. In August 2018, in Docket No. E002/CI-18-251, MPUC established more specific initial filing requirements for Xcel's first IDP.[178] Xcel has submitted its IDP every other year in accordance with these and any subsequently revised or updated filing requirements in 2019, 2021, and most recently 2023.

Xcel filed its 2023 IDP on November 1, 2023 in Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*.[179] MPUC issued a comment period on Xcel's filing and held a

[176] Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E999/CO-16-521, Notice of Comment Period (September 1, 2023).

[177] Minnesota Public Utilities Commission, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, E-999/CI-16-521, Order Establishing a Two-Queue System, Directing Further Discussions, and addressing Miscellaneous Matters (April 15, 2024).

[178] Minnesota Public Utilities Commission, In the Matter of Distribution System Planning for Xcel Energy, Docket No. E-002/CI-18-251, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy (August 30, 2018).

[179] Xcel Energy, In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Docket No. E-002/M-23-452, 2023 Integrated Distribution Plan (November 1, 2023).

hearing to discuss the IDP on July 2, 2024. On September 16, 2024, MPUC issued *Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements*.[180]

In approving Xcel's 2023 IDP, MPUC also included a number of orders directing workgroups to discuss several topics related to DG and interconnection, with the goal of identifying feasible paths forward related to a number of issues, to be included in Xcel's upcoming 2025 IDP filing. These additional requirements aim to enable utilities to meet MPUC's IDP planning objectives, as outlined in the September 16, 2024 Order and as listed below.

- *Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies.*
- *Enable greater customer engagement, empowerment, and options for energy services.*
- *Move toward the creation of efficient, cost effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies.*
- *Ensure optimized use of electricity grid assets and resources to minimize total system costs.*
- *Provide the Commission with the information necessary to understand the utility's short term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.*

The upcoming workgroups and stakeholder processes directed under MPUC's September 16, 2024 Order and its subsequent Notice of Workgroup Processes and Soliciting Stakeholders[181] are summarized below.

In a September 26, 2024 Notice Soliciting Stakeholder Members, MPUC stated that **the DER Cost Sharing Workgroup** (also referred to as **the Reactive Cost Sharing Workgroup**) is tasked with "developing the record more fully in this docket before proposals go before the Commission for decision." The Notice specifically states that the workgroup's efforts should be informed by "perspectives of Minnesota's utilities, businesses, advocates, and other interested participants."[182]

This workgroup aims to fulfill MPUC's legislative directive under Minnesota Session Laws (2024), Chapter 126, Article 6, Section 53, which requires MPUC to, "initiate a proceeding to establish by order generic standards for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities at the congested or constrained location and to advance the achievement of the state's renewable and carbon-free energy goals." At a minimum, the standards must be designed to accomplish the following:

1. *accelerate the expansion of hosting capacity at multiple points on a utility's distribution system by ensuring that the cost of upgrades is shared fairly among owners of distributed generation*

[180] Minnesota Public Utilities Commission, *In the matter of Xcel Energy's 2023 Integrated Distribution Plan,* Docket No. E-002/M-23-452, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024).

[181] Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, Notice of Workgroup Processes and Soliciting Stakeholders (September 27, 2024).

[182] Minnesota Public Utilities Commission, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*, Dockets No. E002,E015,E017/CI-24-288, Notice Soliciting Stakeholder Members (September 26, 2024).

projects seeking interconnection on a pro rata basis according to the amount of the expanded capacity utilized by each interconnected distributed generation facility;

2. *reduce the capital burden on owners of trigger projects seeking interconnection;*
3. *establish a minimum level of upgrade costs an expansion of hosting capacity must reach in order to be eligible to participate in the cost-share process and below which a trigger project must bear the full cost of the upgrade;*
4. *establish a distributed generation facility's pro rata cost-share amount as the utility's total cost of the upgrade divided by the incremental capacity resulting from the upgrade, and multiplying the result by the capacity of the distributed generation facility seeking interconnection;*
5. *establish a minimum proportion of the total upgrade cost that a utility must receive from one or more distributed generation facilities before initiating constructing an upgrade;*
6. *allow trigger projects and any other distributed generation facilities to pay a utility more than the trigger project's or distributed generation facility's pro rata cost-share amount only if needed to meet the minimum threshold established in clause (5) and to receive refunds for amounts paid beyond the trigger project's or distributed generation facility's pro rata share of expansion costs from distributed generation projects that subsequently interconnect at the applicable location, after which pro rata payments are paid to the utility for distribution to ratepayers;*
7. *prohibit owners of distributed generation facilities from using any unsubscribed capacity at an interconnection that has undergone an upgrade without the distributed generation owners paying the distributed generation owner's pro rata cost of the upgrade; and*
8. *establish an annual limit or a formula for determining an annual limit for the total cost of upgrades that are not allocated to owners of participating generation facilities and may be recovered from ratepayers under section 216B.16, subdivision 7b, clause (6)*

The workgroup will develop the regulatory record on this topic in Docket E002,E015,E017/CI-24-288, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas* with these requirements in mind. This proceeding is summarized in greater detail below.

The DER Cost Sharing Workgroup/Reactive Cost Sharing Workgroup will meet for the first time in November 2024.

In addition to the DER Cost Sharing Workgroup/Reactive Cost Sharing Workgroup, MPUC also directed the establishment of a **Proactive Grid Upgrade Workgroup** via Order Point 14 in its September 16, 2024 Order accepting Xcel's 2023 IDP. As stated in MPUC's September 26, 2024 Notice Soliciting Stakeholder Members, the Proactive Grid Upgrade Workgroup is tasked with, "develop[ing] a framework for proactive upgrades and cost allocation for Commission consideration and possible adoption." As stated in Order Point 14(d) and MPUC's October 16, 2024 Notice Soliciting Stakeholder Members in a new docket dedicated to the workgroup (Docket No. E002/CI-24-318),[183] the framework must address (at a minimum) the following topics:

- *How to allocate the costs of proactive upgrades.*

[183] Minnesota Public Utilities Commission, In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy, Docket No. E002/CI-24-318, Notice Soliciting Stakeholder Members (October 16, 2024).

- *How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.*
- *If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.*
- *How a proactive upgrade program would integrate with a utility's planned distribution investment programs.*
- *How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.*
- *How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.*
- *Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).*

Additional detail on Docket No. E002/CI-24-318—where the workgroup will develop the regulatory record on this topic—is summarized in greater detail below. MPUC aims to complete this stakeholder process by July 2025.

Another workgroup established under MPUC's September 16, 2024 Order accepting Xcel's 2023 IDP will be dedicated to identifying **Distribution Data Reporting Requirements** for future IDPs. Order Point 13 from MPUC's September 16 Order "delegate[d] authority to the Executive Secretary to work with Xcel and stakeholders to develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets… to identify which, if any, pieces of information are missing and should be included in future IDPs." In Order Point 13, MPUC specifically directs that the proposal should address data reporting needs related to the following.

- Reliability data such as SAIDI, SAIFI, CAIDI, CEMI, and CELI.
- Distribution spending by IDP budget categories.
- Whether there is available hosting capacity for generation or load at the primary
- system level.
- Demographic data including race and income
- Installed DERs, ECO rebates, DR customers enrolled in programs.
- Data reported at a feeder and/or census block group level.

The Distribution Data Reporting Requirements workgroup is one of three stakeholder processes that make up the overall "IDP Improvements Workgroup," along with an IDP Budget Category Amendments workgroup and an IDP Filing Requirements for Electrification workgroup, both of which are also outlined in MPUC's September 27, 2024 Notice of Workgroup processes and Soliciting Stakeholders.

The Distribution Data Reporting Requirements workgroup will start meeting in 2025 to discuss the topics listed above.

The Order also directed the establishment of a **Flexible Interconnection Working Group**, to be convened as part of the **Distributed Generation Working Group** (DGWG). The DGWG—established via a January 24, 2017 MPUC Order in Docket No. 16-521—has met on an ongoing basis to discuss and resolve issues related to DG and interconnection in Minnesota, and to develop the regulatory record on these topics as needed.[184]

In its September 16, 2024 Order accepting Xcel's 2023 IDP, MPUC identified flexible interconnection (Flex IX), including distributed energy resource management systems (DERMS) as "an emerging DER control strategy that can enable more DER integration by avoiding the normal system upgrades that may be necessary under traditional interconnection. Without those necessary system upgrades, DERs may be curtailed when the grid is constrained, but the DERs get the benefit of a lower cost interconnection and the ability to operate at full capacity when the grid is not constrained."

Via Order Point 19, MPUC directed Xcel to "demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term" including Flex IX and DERMs. Via Order Point 21, MPUC directed the DGWG "to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS." MPUC's September 27, 2024 Notice of Workgroup Processes and Soliciting Stakeholders directs stakeholders participating in the Flexible Interconnection Working Group to attend the November DGWG meeting, where priorities will be established in accordance with Order Point 19.

Order 21 in MPUC's Order accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements in Docket No. E-002/M-23-452 states the following: "The Commission directs the Distributed Generation Workgroup to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS." DGWG is ongoing, continues to meet to address and discuss issues on schedules as identified by MPUC. Flexible Interconnection Working Group members to attend November DGWG meeting, where priorities related to flexible interconnection will be discussed.

Similarly, MPUC's Order accepting Xcel's 2023 IDP additional directs the establishment of an Xcel-led stakeholder process focused on **Cost-Benefit Analysis, DERMs, and Planned Net Load**. MPUC's order directs Xcel to conduct stakeholder outreach on a number of items related to its distribution system. Order Points 10–12 direct Xcel to, "engage in additional stakeholder discussions on approaches to apply cost-benefit analyses… strategically to program-level investments for discretionary projects for certification or cost recovery proceedings," and "explain how it would define 'discretionary' spending in this context."

Similarly, Order Point 17 directs Xcel to, "work with stakeholders to refine its planned net load methodology [and] evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity."

Finally, Order Point 22 directs Xcel to conduct stakeholder outreach directly with DER owners/operators to inform such stakeholders about numerous factors related to DERMS including costs/benefits,

[184] Minnesota Public Utilities Commission*, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611*, Docket No. E-999/CI-16-521, Order Establishing Workgroup and Process to Update and Improve State Interconnection Standards (January 24, 2017).

Minnesota Public Utilities Commission, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611*, Docket No. E-999/CI-16-521, Notice Soliciting Distributed Generation Workgroup Members (February 14, 2017).

alternatives to DERMS, and the purpose of using DERMS (i.e., the problems that DERMS aims to address).

Docket No. E002,E015,E017/CI-24-288: In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas

Minnesota Session Laws (2024), Chapter 126, Article 6, Section 53 directed MPUC to, "initiate a proceeding to establish by order generic standards for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities at the congested or constrained location and to advance the achievement of the state's renewable and carbon-free energy goals." On August 30, 2024, MPUC opened a new docket (Docket No. E002, E015, E017/CI-24-288) in accordance with this requirement.

On September 26, 2024, MPUC issued a Notice Soliciting Stakeholder members in this proceeding. In this notice, MPUC established a DER Cost Sharing Workgroup (also sometimes referred to as the "Reactive Cost Sharing Workgroup"), which it, "tasked with developing the record more fully in this docket before [cost sharing] proposals go before the Commission for decision."[185] The proceeding will occur across three phases, as summarized below.

- Phase 1: The DER Cost Sharing Workgroup will meet jointly with the Proactive Grid Upgrade Workgroup (described in greater detail below under Docket No. E002, E015, E017/CI-24-318). During this phase, the two workgroups will discuss differences in scope and timelines between the DER Cost Sharing Workgroup and the Proactive Grid Upgrade Workgroup, as well as areas of topical overlap.
- Phase 2: Meetings held during this phase will enable open communication among DER Cost Sharing Workgroup as the group discusses technical requirements outlined in Minnesota Session Laws (2024), Chapter 126, Article 6, Section 53 including expanding hosting capacity, reducing the cost burden on individual projects that may trigger upgrade needs, and more.
- Phase 3: This phase will include a formal comment period in the proceeding, with the goal of developing the written record on issues and solutions. Phase 3 will be informed by prior phases in the proceeding.

The DER Cost Sharing Workgroup (or Reactive Cost Sharing Workgroup) is scheduled to begin meeting in November 2024. MPUC currently anticipates that Phase 3 of the proceeding will conclude with an Agenda Meeting in Fall 2025.

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[185] Minnesota Public Utilities Commission, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*, Dockets No. E002,E015,E017/CI-24-288, Notice Soliciting Stakeholder Members (September 26, 2024).

Docket No. E002,E015,E017/C~~I~~24~~-~~318: In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy

On September 16, 2024, MPUC issued an Order in Xcel's 2023 Integrated Distribution Planning (IDP) docket. Order Point 14 directs MPUC's Executive Secretary, "to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel," (other utilities may elect to participate in the stakeholder process), with the goal of completing the stakeholder process by July 1, 2025.[186] As stated above in the Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan* summary, Order Point 14(d) of MPUC's September 16, 2024 Order establishes that the framework should address the following topics, at a minimum:

- viii) *How to allocate the costs of proactive upgrades.*
- ix) *How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.*
- x) *If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.*
- xi) *How a proactive upgrade program would integrate with a utility's planned distribution investment programs.*
- xii) *How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.*
- xiii) *How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.*
- xiv) *Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC)*

On September 26, 2024, MPUC opened Docket No. E002/CI-24-318, *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy* in accordance with Order Point 14 in its September 16, 2024 Order in Docket No. E-002/M-23-452. On September 26, MPUC issued a Notice Soliciting Stakeholder Members for a Proactive Grid Upgrade Workgroup, which will further develop the administrative record on this topic in fulfillment of the requirements outlined in Order Point 14.[187]

Like the process described above under Docket No. E002/CI-24-288 summary, the Proactive Grid Upgrade Workgroup will meet throughout a three-phase process.

- Phase 1 will consist of the joint meeting with the DER Cost Sharing Workgroup/Reactive Cost Sharing Workgroup, as summarized above.
- Phase 2 will focus on the topics outlined in Order Point 14 in MPUC's Order approving Xcel's IDP.

[186] Minnesota Public Utilities Commission, *In the matter of Xcel Energy's 2023 Integrated Distribution Plan,* Docket No. E-002/M-23-452, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024).

[187] Minnesota Public Utilities Commission, *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy,* Docket No. E002/CI-24-318, Notice Soliciting Stakeholder Members September 26, 2024).

- In Phase 3, MPUC will issue a Notice of Comment in the proceeding to further develop the record on this topic. Phase 3 will be informed by prior phases in the proceeding.

The Proactive Grid Upgrade Workgroup is scheduled to begin meeting in November 2024. MPUC currently anticipates that Phase 3 of the proceeding will conclude with an Agenda Meeting in Fall 2025.