U.S. DEPARTMENT OF
ENERGY
Secretary of Energy Advisory Board

Recommendations on Grid Modernization

Presented to the Secretary of Energy

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I. Introduction

During the inaugural meeting of her Secretary of Energy Advisory Board (SEAB) in October 2021, Secretary of Energy Jennifer M. Granholm identified several priority areas for her tenure as Secretary. One of these areas was modernizing the Nation's electricity grid so that all Americans can have clean and affordable power. Based on her priorities, the SEAB formed the Grid Modernization working group which is focused on making recommendations relative to how the Department can execute its authority to ensure that the Secretary's priorities are met.

Congress provided the Department with additional authority and funds to further grid modernization through legislation known as the Infrastructure Investment and Jobs Act (IIJA) or Bipartisan Infrastructure Law (BIL) in November 2021. The BIL gives the Department historic amounts of money to fund projects such as electric transmission, smart grid, electric vehicle infrastructure, and resilience projects throughout the Nation. With this authority came the exigency to create and manage programs throughout the Department in order to achieve impactful results.

This report focuses recommendations on three provisions of the IIJA: "Transmission Facilitation Program" (Section 40106), "Deployment of Technologies to Enhance Grid Flexibility" (Section 40107), and a potential matching grant program for utility participants under "Preventing Outages and Enhancing the Resilience of the Electric Grid" (Section 40101).

II. Methodology

Members of the Grid Modernization working group of SEAB conducted over 20 phone and in-person meetings with various stakeholder groups such as state energy offices, state utility commissions, developers, investors, grid operators, trade associations, Federal Energy Regulatory Commission (FERC), and grid planners as well as DOE staff in the development of these recommendations.

III. Transmission Facilitation Program

The Transmission Facilitation Program (TFP) enables DOE to provide financing and enter into capacity contracts with new or upgraded transmission facilities. DOE may serve as a lender or anchor customer for upgraded and new lines with a capacity of over 1,000 megawatts (MW). The Department can also enter public-private partnerships to develop new transmission lines in National Interest Electric Transmission Corridors (NIETC), pursuant to the Energy Policy Act (EPAct) of 2005.

The IIJA describes eligible uses of the TFP as "(A) to construct a new or replace an existing eligible electric power transmission line; (B) to increase the transmission capacity of an existing eligible electric power transmission line; or (C) to connect an isolated microgrid to an existing transmission, transportation, or telecommunications infrastructure corridor located in Alaska, Hawaii, or a territory of the United States."

Recommendations on TFP Implementation:

The following recommendations are grouped into five categories:

- Guiding criteria.
- Project Screening criteria, which identify 3 tiers of project.
- The application process for potential TFP projects.
- Suggested mechanics for capacity purposes under the TFP.
- Mechanism for loans under the TFP.

Guiding Criteria:

- Seek early successes by assisting "shovel ready" projects.
- Prioritize interstate projects that will facilitate more renewables that otherwise might not be completed.
- Prioritize projects that facilitate regional power flows.
- Design a program to facilitate rapid fund recycling.
- Upsizing of transmission projects in anticipation of future needs to integrate renewables.

Project Screening Criteria

DOE should provide a window of opportunity for utilities and developers to apply for project support. As projects are received, they will be classified as Tier One, Tier Two, or Tier Three. DOE should give priority to Tier One projects, whose development status means they might get into construction in the next 24 months.

DOE should use the following criteria as a guideline to gauge the state of project development as opposed to immutable numerical objectives.

Tier One: Advanced Development or Shovel Ready

- Interconnection agreements have been signed.
- 90%+ of right of way is in place, with a clear path for acquiring the remaining ROW easements.
- Major permits such as Federal Special Use Permits or Rights of Way on Federal land or state Certificate of Public Necessity and Convenience Need are in place.
- 25% of the project capacity sold to other purchasers.
- A third party study that describes why a line is likely to fill up once built.
- The project is backed by developer or utility with significant financial resources (i.e., developer equity greater than 2X project equity requirements).

Tier Two: Mid Stage Development

- Interconnection processes are underway with receipt of System Impact Study.
- Right of Way (ROW) acquisitions are underway, with some right of way already secured (i.e., 20% of ROW secured, or 60% applied for).
- Major permit applications such as Federal Special Use Permits or Rights of Way on Federal land or state Certificate of Public Necessity and Convenience have been submitted and are under review.
- Expressions of interest from future capacity customers have been received.

- Compelling explanation of need for the line, either from a project proponent or a third-party study. Because Regional Transmission Organization (RTO) processes often do not consider interregional projects, a failure to include a project in an RTO process should not be a project disqualifier.
- Financial backing is in place to carry the project through the development process.

Tier Three: Early-Stage Projects

- Interconnection requests have been submitted.
- ROW process has been clearly outlined and regulatory processes have been initiated.
- Studies to support major permits are underway.
- Project rationale has been clearly articulated.
- Financial backing for early development is in place (i.e., $5,000 per MW of line capacity, or $5 million for a 1,000 MW line).

Application Process

DOE should accept TFP applications on a rolling basis. Projects would be qualified quarterly, or in the case of projects whose development advances through the tiers, DOE would upgrade their status as the developer provides more evidence of advancement.

To the extent that there are more Tier 1 projects than funding available, projects should be evaluated against one another on a DOE dollars per subscribed MW enabled basis. The project which enables the most renewable MWs per DOE dollar should advance ahead of its peers. This rationale should incentivize developers to subscribe as many MW's as possible before applying to DOE.

At a project proponents' request, DOE would publicly announce its selection of projects at the Tier One, Two and Three levels to signal to other branches of government that such projects merit support.

Suggested Mechanics for Capacity Purchases

The actual mechanics of DOE capacity purchases are important to minimize risk to DOE and to ensure that DOE funds are returned to DOE or commitments are released. This will ensure that new projects can participate in the program and more transmission lines can get built. The following is a suggested sequence:

- Project proponent must have sold at least 25% of capacity for DOE to purchase any capacity.
- DOE would purchase up to 50% of available capacity but never more than 66% of available capacity in order to ensure that project proponent also maintains some investment risk. For example, if a line were 33% subscribed, the government could purchase 44%, leaving the developer with an open position of 23%. If a line were 25% subscribed, DOE could purchase 50%. If line were 50% subscribed, DOE could buy 33%, leaving the developer with 17%.
- As a developer sells off its capacity, DOE would have the right to "tag along" on a 2:1 ratio. For example, if a developer sells 100 MW, DOE could tag along with 200 MW.

This mechanism is designed to ensure that DOE's purchasing capacity is freed up as quickly as possible to make capacity available for other meritorious projects. By the time the project proponent has sold its capacity, DOE will be out as well.

Other Considerations

DOE will need to articulate timing mechanics for the period between when they consider an application complete, and DOE makes capacity commitment – managing the tension between ensuring DOE arrives at closing table with ability to commit to capacity without finding itself in a position where projects "squat" on DOE commitments.

At the signing of a participation agreement, a developer must sign a security agreement of $25,000 per MW for each MW of capacity government would commit to purchase (i.e., $25 million for a 1,000 MW commitment).

For projects whose costs are partially cost allocated, DOE capacity commitments would only apply for unsubscribed capacity on these major transmission lines not subject to cost allocation. This measure will facilitate upsizing or rightsizing of new transmission lines in further preparation for a low-carbon future.

The portion of the new line not subject to cost allocation must be at least 500 MW.

Projects which are fully cost-allocated should not qualify.

Projects with capacity contracts already in place may participate, but only to the extent they have unallocated capacity available.

Mechanism for Loans

Loans may be more advantageous to DOE as opposed to long term capacity commitments, due to government accounting rules. Commitments to purchase capacity may take up too much of DOE's $2.5 billion in available resources.

This program would function similar to the capacity agreement outlined above.

Loans would be structured in a way that DOE as the lender, would bear the risk of whether the transmission lines fill up.

DOE would lend against half the value of the capacity of the line. Project proponents in all cases would be required to have sold some project capacity (for example 25%). Projects would borrow against their market capacity sales and against DOE capacity sales. As projects sold off more capacity, DOE's loan would be paid back, replaced by the commercial lender. Ultimately as the line filled up, DOE would end up with loan balance fully replaced by commercial lenders.

The involvement of a commercial lender who lent against, for example, the 25% capacity sales, would allow DOE to piggyback on the commercial lender's due diligence efforts.

IV. Deployment of Technologies to Enhance Grid Flexibility

The IIJA defines eligible uses in this section as including "data analytics enabling software smart grid functions; building devices and software supporting demand flexibility and smart grid functions; operational fiber and wireless broadband communications networks enabling data flow between distribution system components; and advanced transmission technologies, including dynamic line rating, flow control devices, advanced conductors, and network topology optimization, to increase the operational transfer capacity transmission networks."

Recommendations on Program Implementation:

DOE's program implementation of this provision should include the following considerations:

- Reopening the program for applications in a timely fashion given its previous iteration through the American Recovery & Reinvestment Act of 2009.
- DOE should provide an open window for utilities and developers to apply for project support. To encourage as much innovation as possible independent developers, manufacturers, and others should be able to propose projects to DOE if there is an identified and committed end user and the Qualifying Smart Grid Investment will be deployed within 18 months.
- DOE should hold a joint technical conference with FERC to examine how the two agencies together could most effectively collaborate to support GETs deployment on the grid.
- DOE should make grants to RTOs to study deployment of Grid Enhancing Technologies (GETs) in their systems. Under the statute, the Secretary may identify "[s]uch other functions" that are necessary or useful to the operation of a Smart Grid.
- DOE should make technical assistance and modeling resources available to public power utilities as they consider how implementing these innovative technologies would impact their systems.
- Make sure that when a utility deploys GETs, installation costs such as RTO software upgrades, personnel training, data links and other costs associated with the deployment of GETs qualifies as a match under the bill's match requirements.
- With the increased number of distributed resources, planning and operations is increasingly dependent on accurate forecasting of conditions which are dependent on additional variables that traditional load forecasting techniques are not designed to cover. DOE should seek out opportunities that improve net load and DER forecasting techniques to determine the impact of DERs at each T-D interface substation.

Guiding Criteria:

- Maximize use of existing transmission grid to facilitate high volumes of zero carbon energy.
- Enable projects and technology deployment which would not ordinarily happen on their own.
- Prioritize projects that facilitate regional and interregional power flows.
- Deployment of technologies to reduce bottlenecks in transmission interconnection queues.
- Supporting uses that provide the greatest benefit-cost ratio.

DOE should consider the following as they allocate the $3 billion in Smart Grid Investment Grant (SGIG) funding:

- DOE should reserve most of the program funds to add intelligence, control, and capability to the bulk transmission grid. The remainder of the program funds should be allocated to electric distribution improvements that enable grid edge applications involving, among other things, demand response, distributed energy resources, the use of EVs.
- DOE should not fund retail level smart meters as this technology has already been broadly adopted.
- DOE should evaluate transmission grid projects based on impact as measured by congestion relief (cost savings) and renewables connected with a preference towards projects that can deliver quickly.
- DOE should consider a grant program to support a nationwide revamping of line ratings. Funds could be channeled through the RTOs or in the case of regulated markets, directly to transmission owners. Counterparties should receive full credit for staff time, software changes and upgrades, and other related costs.
- DOE should create a small grant program to provide technical assistance to the states and state energy offices and ratepayer advocates so that they have the tools and knowledge to advocate for GETs.

V. Preventing Outages and Enhancing the Resilience of the Electric Grid

Under certain provisions of the BIL, DOE can provide matching grants of up to 50% for transmission projects which enhance grid resiliency. As a result of Winter Storm Uri (February 2021), there is substantial evidence supporting the criticality of transfer capability across the Eastern Interconnection to both the reliability and resiliency of the grid. This benefit of added resiliency is often not fully considered in transmission planning as it is difficult to quantify. Although this benefit was apparent during Winter Storm Uri, the transmission capacity that was available and heavily used was built for reasons unrelated to emergency usage during extreme weather events. DOE might consider creating a program in which all stakeholders (e.g., regional transmission organizations, other transmission providers, dialogue states, and member utilities) collaborate (with packages of transmission lines which those entities propose) to enhance regional resiliency. DOE should focus their consideration on interregional transmission lines. This may dovetail with a proposal at FERC to require a certain amount of transfer capacity across regions, so collaboration with FERC may also be helpful.

A prime example of a meritorious set of projects would be those identified by the newly completed Joint Targeted Interconnection Queue (JTIQ) study recently undertaken by Southwest Power Pool (SPP) and The Mid-Continent Interconnection System Operator (MISO). The JTIQ study process contemplates building transmission network upgrades along the MISO-SPP seams to enable new generator interconnections and provide benefit to load in both regions. The improvements proposed by the JTIQ will optimize the transmission needed for interconnection of the evolving resource mix across the seams, since the transmission system is currently at capacity along the SPP-MISO seam and upgrades are too costly for small groups of interconnection customers. This has contributed to problems with both RTO queues. These improvements will enable reliable interconnection of significant amounts of new generation while providing $724 million of Adjusted Production Cost savings to ratepayers in MISO and $247 million of APC savings to ratepayers in SPP. These lines are also expected to inherently enhance the reliability and resiliency of both regions and improve the two RTOs' ability to respond to extreme weather.

SPP and MISO are now working to determine how to pay for $1.7 billion of interregional alternating current (AC) transmission lines that have been identified as a result of this joint collaboration. These new lines would unlock 28-5320+ gigawatts (GW) of new renewables and produce benefits to load. However, without resolution of cost allocation issues between load and generators across a broad geography, these projects may not get built.

Recommendations

If the Federal government were to create a program whereby DOE paid a substantial portion of the cost of interregional upgrades, RTO's, load, states, and generators would have a substantial incentive to work together to get the projects built. For example, in the case of JTIQ, DOE might pay for half of the cost with the remainder allocated 25% to load and 25% to generators whose projects were enabled by the grid improvements. Another option might be to advance part or all the funding for the lines but to be reimbursed on a pro rata MW basis by generators as they interconnect. (CAISO successfully used this approach to develop transmission facilities that enabled the interconnection of renewables in Tehachapi.)

A program like this would gain a potent set of allies and outcomes, as follow:

- Renewable generator developers and load-serving utilities in SPP and MISO would have a greater incentive to figure out cost sharing across their footprints
- State commissions would keep an eye on utility expenditures and would make sure that ratepayers benefitted.
- Utilities and independent transmission companies (transcos), who are the parties best suited to site, build, own and operate additions to the AC network, would push hard to build the lines because they want to grow their businesses. Utilities would not get to add the full $1.7 billion into rate bases, but $425 million of new investment opportunities would certainly attract their interest (the 25% of projects that would be cost allocated).
- RTOs, who are in the business of maintaining reliability, would be helpful and independent protagonists.
- RTOs would resolve one of the major concerns expressed by stakeholders because the JTIQ projects would help unclog interconnection queues, which is one of the biggest challenges facing RTO's.
- The lines would create resiliency benefits and lower costs to ratepayers by bringing many GWs of low-cost renewables onto the grid.

Criteria for the Interregional Resiliency Matching Grant Program

In general, funds under the Interregional Resiliency Matching Grant program should be allocated using the following criteria:

- Groups of projects whose cost allocation is otherwise difficult to resolve. Note this concept could be applied to help with the advancement of transmission upgrades in backlogged generation interconnection queues that are more than several years in arrears.
- Projects that do not create windfalls for utilities or independent developers.
- Projects that enhance reliability and resilience, particularly those that would have helped avoid issues like those of recent extreme weather events (Heat Dome in Northwest, Winter Storm Uri, etc.)
- Projects that maximize renewables penetration and carbon reduction.
- Projects with multiple RTO or utility sponsors.
- Longer term, DOE may also wish to coordinate its efforts in identifying National Interest Electric Transmission Corridors (NIETC) with funding opportunities in this program. In other words, the criteria should consider whether a transmission project addresses NIETC needs. This would support the development of a particularly impactful transmission.

Grid to Grid Projects

HVDC connections between the grids would be immensely helpful for both reliability and new renewables integration. Unfortunately, unlike the JTIQ, they currently fall outside of the existing planning processes. Many studies have documented the benefits to enhanced ties between the Eastern and Western Interconnects as well as between ERCOT and the outside world. There are substantial benefits provided by these enhancements that could accrue to ratepayers. However, there are great challenges to facilitating these HVDC line enhancements. The lack of a workable interregional planning process, particularly across the Interconnects, means that there is no planning approval which can help facilitate the later siting of these projects. The other existing challenge is that the bigger one builds these lines (i.e., 3 GW vs. 1 GW, for example), the more the arbitrage is eroded between the two grids (and the arbitrage may be the main source of value that inter-grid tie owners can capture and generate a return on their capital), and the less revenue is available. In other words, by fixing the problem, one decreases the revenue stream needed to fund the project. This challenge with grid-to-grid ties means that it is difficult for the project owner to capture sufficient economics, especially when lines are “right sized” for the true needs of the grid.

The best way to resolve the issue would be similar in some respects to the idea proposed above; through an applicant driven process, project proponents would nominate projects for government support. If a project were selected based on its ability to enhance reliability and renewable integration, DOE would pay for half the cost. The other half of the cost would be allocated between the RTO’s and/or transmission providers on either end of the line (e.g., WECC and MISO), but at a much-reduced cost to ratepayers. The RTOs would have every incentive because the lines would help their systems. The project proponent would recover costs through rates collected on either end of the line.

Other Considerations

The current DOE loan program and the soon to be created Transmission Infrastructure Program will work best for long gen ties where the benefits accrue primarily to the owners of the line. Both programs are likely to solve the problem of taking the risk that big GW plus lines fill up. Once they do, the lines can pay for themselves, especially if there is an investment tax credit. The "anchor tenant" program in the BIL will work in a similar fashion.

In the case of both AC and DC lines, DOE's participation should be structured as a match instead of outright ownership of the line because DOE ownership might require the project to go through a NEPA process, which significantly increases costs and lengthens the schedule.

VI. Conclusion

Through the effective implementation of the provisions of the BIL discussed above, DOE can effectuate substantial development of the transmission system and grid. The authority and funding that Congress provided to DOE offer tremendous opportunity for real change. The SEAB believes following these recommendations while also evaluating each program's progress on a regular basis will ensure positive outcomes for the grid for years to come.