

119TH CONGRESS
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H. R. 6176

To require standardized performance reporting for entities engaged in electricity transmission to improve transparency, accountability, and grid outcomes, and for other purposes.

IN THE HOUSE OF REPRESENTATIVES

NOVEMBER 20, 2025

Mr. CASTEN (for himself, Mr. MULLIN, Mr. HUFFMAN, Mr. SUBRAMANYAM, Mr. QUIGLEY, Mr. GARAMENDI, Ms. CASTOR of Florida, Mr. MOULTON, Mr. FOSTER, Mr. LEVIN, and Mr. CARSON) introduced the following bill; which was referred to the Committee on Energy and Commerce

A BILL

To require standardized performance reporting for entities engaged in electricity transmission to improve transparency, accountability, and grid outcomes, and for other purposes.

1 *Be it enacted by the Senate and House of Representa-*
2 *tives of the United States of America in Congress assembled,*

3 **SECTION 1. SHORT TITLE.**

4 This Act may be cited as the “Electricity Trans-
5 mission Scorecard Act”.

6 **SEC. 2. FINDINGS.**

7 Congress finds the following:

1 (1) Electricity transmission facilities and serv-
2 ices provided by covered transmission owners affect
3 interstate commerce and are essential to the Na-
4 tion’s economic well-being and national security.

5 (2) Transparent, standardized performance
6 data on transmission systems promotes cost-effective
7 investment, prevents unduly discriminatory prac-
8 tices, and protects ratepayers.

9 (3) Existing reporting requirements are frag-
10 mented, inconsistent, and do not allow for meaning-
11 ful comparison among transmission providers,
12 RTOs, and ISOs.

13 (4) To ensure that all transmitting utilities are
14 subject to uniform, non-discriminatory access obliga-
15 tions, to safeguard the public interest in the reli-
16 ability, affordability, and efficiency of the interstate
17 transmission system, and to ensure the development
18 of just and reasonable rates, a common performance
19 reporting framework is necessary.

20 (5) Systemic transparency across all utilities
21 engaged in transmitting electricity enables rate-
22 payers, investors, generators, regulators, researchers,
23 and other stakeholders and market participants to
24 clearly compare transmission rates, outcomes, and
25 practices across regions and governance structures.

1 (6) Market and policy innovation in the elec-
2 tricity sector is enhanced by making grid perform-
3 ance data publicly available, thus empowering inde-
4 pendent research, enabling competition, and reduc-
5 ing information asymmetries between utilities and
6 external actors.

7 (7) The quality of economic, reliability, and en-
8 vironmental outcomes delivered to customers can im-
9 prove as a result of performance-based account-
10 ability.

11 (8) It is in the best interest of the Nation to
12 require standardized data submissions and scorecard
13 reporting from all utilities engaged in transmitting
14 electricity, including those not subject to section 205
15 or 206 of the Federal Power Act, to evaluate wheth-
16 er service comparability and nondiscrimination obli-
17 gations are being met and to ensure that ratepayers
18 are not burdened by inefficiencies, lack of invest-
19 ment, or the absence of cost-effective solutions that
20 would increase capacity, reduce congestion, facilitate
21 interconnection, or otherwise reduce unnecessary
22 costs and reliability concerns for ratepayers.

23 **SEC. 3. PERFORMANCE SCORECARD ELEMENTS AND**
24 **VERIFICATION.**

25 (a) REPORTING REQUIREMENTS.—

1 (1) TRANSMISSION INVESTMENT, ACCOUNT-
2 ABILITY, AND PERFORMANCE SCORECARDS.—

3 (A) IN GENERAL.—The Commission shall
4 require each covered transmission owner to bi-
5 annually develop, publish, and submit to the
6 Secretary a report, to be known as a Trans-
7 mission Investment, Accountability, and Per-
8 formance Scorecard (or a TIAPS report), that
9 includes metrics evaluating the following:

10 (i) Ratepayer affordability, which
11 shall assess the cost of transmission serv-
12 ices per unit of energy transmitted or
13 other metrics that can be used to assess
14 affordability of energy provided to rate-
15 payers.

16 (ii) Financing costs, which shall as-
17 sess the financing structure and cost of
18 capital for a covered transmission owner,
19 and may include consideration of capital
20 structure and leverage ratios, reliance on
21 formula rates or other automatic adjust-
22 ment mechanisms, allowed and earned re-
23 turns on equity, the cost of debt and pre-
24 ferred stock, the presence and magnitude

1 of incentive rate adders, and other related
2 metrics.

3 (iii) Investment prudence and cost re-
4 covery, which shall assess the prudence of
5 capital investments and the transparency
6 and structure of associated cost recovery
7 mechanisms, and may include the fre-
8 quency and magnitude of cost disallow-
9 ances in rate proceedings, the types of fa-
10 cilities or investments associated with dis-
11 allowed costs, the degree of cost recovery
12 from ratepayers relative to shareholder
13 contributions, and the transparency and
14 accountability of cost allocation frame-
15 works.

16 (iv) Investment effectiveness, which
17 shall assess the value delivered by covered
18 transmission owner investments relative to
19 their costs, including how effectively the
20 covered transmission owner considered and
21 deployed the most economically efficient
22 solutions to reduce cost burden on rate-
23 payers and the accuracy of project cost es-
24 timates, and may include metrics related to
25 benefit-cost analyses, investments in ad-

1 vanced technology deployment, non-wires
2 alternatives, reconductoring, grid-enhanc-
3 ing technologies, or other operational up-
4 grades that avoid higher cost capital in-
5 vestment, estimated and actual cost for
6 new or updated assets, and other indica-
7 tors of prudent capital deployment.

8 (v) Capital expenditure bias, which
9 shall assess the covered transmission own-
10 er's balance of spending on capital invest-
11 ment versus operational and maintenance
12 activities.

13 (vi) System reliability and availability,
14 which shall assess the operational perform-
15 ance of the transmission facilities of the
16 covered transmission owner over the re-
17 porting period, including information re-
18 lated to outages, equipment availability,
19 and resilience to system disturbances, and
20 may be expressed using existing trans-
21 mission-specific reliability indicators, as de-
22 scribed by the North American Electric
23 Reliability Corporation or other entity es-
24 tablished to oversee and administer reli-
25 ability standards and procedures for the

1 bulk-power system, metrics regarding the
2 economic costs of outages or lost reli-
3 ability, or other related metrics.

4 (vii) Physical system performance,
5 which shall assess how effectively the
6 transmission facilities owned, operated, or
7 controlled by the covered transmission
8 owner are used to deliver electricity, in-
9 cluding both physical and economic per-
10 formance, and may include technical and
11 non-technical losses, utilization relative to
12 rated capacity and design constraints, age
13 of system components, and other indicators
14 of transmission system utilization, per-
15 formance, and efficiency.

16 (viii)(I) Interconnection and access
17 fairness, which shall assess the extent to
18 which the interconnection process for inter-
19 regional interconnections and new facilities
20 (including generators, energy storage, load,
21 and merchant transmission projects) is
22 conducted in a timely and impartial man-
23 ner consistent with Commission regula-
24 tions, including comparisons between affili-
25 ated entities and unaffiliated entities, and

1 may be expressed as the difference in the
2 number of days from initial interconnection
3 request to execution of an Interconnection
4 Agreement, or through related measures of
5 procedural equity.

6 (II) For purposes of this clause:

7 (aa) The term “affiliated entity”
8 means any entity that has a direct or
9 indirect relationship with a covered
10 transmission owner or its parent enti-
11 ty that could reasonably influence
12 interconnection treatment, including
13 an entity that—

14 (AA) shares common owner-
15 ship or controlling interest with
16 the covered transmission owner
17 or its parent entity;

18 (BB) is a direct or indirect
19 subsidiary of the covered trans-
20 mission owner or its parent enti-
21 ty;

22 (CC) is engaged in a joint
23 venture, contractual partnership,
24 or strategic alliance with the cov-
25 ered transmission owner or its

1 parent entity, where such part-
2 nership includes shared financial
3 interest, revenue sharing, or
4 asset co-development; or

5 (DD) is otherwise deter-
6 mined by the Commission to have
7 a financial, governance, or oper-
8 ational relationship that may rea-
9 sonably be expected to influence
10 interconnection prioritization.

11 (bb) The term “unaffiliated enti-
12 ty” means any entity that—

13 (AA) has logged an inter-
14 connection request with the cov-
15 ered transmission owner; and

16 (BB) is not an affiliated en-
17 tity.

18 (ix) Non-operational cost recovery,
19 which shall assess the amount of covered
20 transmission owner spending on lobbying,
21 advertising, penalties, and advocacy activi-
22 ties recovered through customer rates, and
23 may be expressed as expenditures on each
24 such activity, a total sum of expenditures
25 on such activities, or related metrics.

1 (x) Interregional and regional plan-
2 ning integration, which shall assess the ex-
3 tent to which the covered transmission
4 owner participates in coordinated regional
5 and interregional transmission planning
6 processes and infrastructure development,
7 and may be expressed as the number and
8 capacity of interregional transmission ties,
9 the share of projects subject to regional or
10 interregional planning review, or related
11 metrics.

12 (xi) Any additional matters that—

13 (I) may be evaluated using out-
14 come-based performance metrics iden-
15 tified by the Commission, giving pref-
16 erence to quantitative metrics over
17 qualitative metrics; and

18 (II) the Commission determines
19 are necessary to improve trans-
20 parency, affordability, reliability, eq-
21 uity, or environmental performance of
22 the facilities owned, operated, or con-
23 trolled by the covered transmission
24 owner.

25 (B) EXEMPTIONS.—

1 (i) CATEGORIES.—The Commission
2 may, by rule, exempt all covered trans-
3 mission owners in a category of covered
4 transmission owners from the requirement
5 to include a metric described in subpara-
6 graph (A) if the Commission determines
7 that the metric is demonstrably inappli-
8 cable to all covered transmission owners in
9 the category.

10 (ii) SCOPE.—The Commission shall
11 ensure that the scope of any metric from
12 which a category of covered transmission
13 owners is exempted under this subpara-
14 graph is as narrow as possible in order to
15 preserve consistency and comparability
16 among scorecards.

17 (C) COORDINATION.—In preparing and de-
18 veloping a scorecard pursuant to this para-
19 graph, a covered transmission owner shall co-
20 ordinate, as necessary to obtain or estimate
21 data required to be included in a scorecard
22 under this section, with any relevant entity, in-
23 cluding—

24 (i) regional grid operators, including
25 Independent System Operators, Regional

1 Transmission Organizations, transmission
2 planning entities, and balancing authori-
3 ties;

4 (ii) interconnected electric utilities, in-
5 cluding load serving entities and other
6 transmission providers;

7 (iii) owners of generation facilities, in-
8 cluding utility-scale and merchant genera-
9 tors seeking interconnection or operating
10 within the service territory of the covered
11 transmission owner; and

12 (iv) regulatory and oversight entities,
13 including State public utility commissions,
14 and applicable Federal or State energy, re-
15 liability, or environmental agencies.

16 (2) REGIONAL INVESTMENT, ACCOUNTABILITY,
17 AND PERFORMANCE SCORECARDS.—The Commission
18 shall require each Independent System Operator,
19 Regional Transmission Organization, and trans-
20 mission planning entity to annually develop, publish,
21 and submit to the Secretary a report, to be known
22 as a Regional Investment, Accountability, and Per-
23 formance Scorecard (or a RIAPS report), that in-
24 cludes the following:

1 (A) Aggregation of the metrics reported
2 for the year in the scorecards submitted under
3 paragraph (1) by the covered transmission own-
4 ers within the jurisdiction of the applicable
5 ISO, RTO, or transmission planning entity,
6 which shall consist of a summary of such
7 metrics that—

8 (i) reflects weighted or capacity-ad-
9 justed averages of covered transmission
10 owner-reported metrics, as appropriate;

11 (ii) highlights significant intra-re-
12 gional variation or performance outliers;
13 and

14 (iii) does not obscure material dif-
15 ferences among transmission owners or re-
16 gions.

17 (B) Regional-specific metrics, which shall
18 consist of reporting on metrics specific to oper-
19 ational responsibilities of the ISO, RTO, or
20 transmission planning entity, including the fol-
21 lowing:

22 (i) Market efficiency, which shall as-
23 sess the extent to which the ISO, RTO, or
24 transmission planning entity is successful
25 in operating efficient wholesale electricity

1 markets, minimizing system congestion,
2 and maximizing the use of existing grid in-
3 frastructure to deliver cost-effective out-
4 comes for consumers while maintaining re-
5 quired standards of reliability, and may be
6 expressed as average energy and ancillary
7 service costs (system-wide and by major
8 zone), system and zonal capacity costs
9 where applicable, congestion costs, out-of-
10 market payments, frequency of redispatch,
11 implementation of congestion-relieving
12 technologies, or related metrics.

13 (ii) Regional interconnection perform-
14 ance, which shall assess the effectiveness
15 and efficiency of interconnection processes,
16 and may include metrics that measure the
17 duration of queue processing, the rate of
18 project withdrawals, and the share of
19 projects that successfully reach commercial
20 operation, or related metrics.

21 (iii) Regional and interregional devel-
22 opment, which shall assess the extent and
23 effectiveness of regional and interregional
24 transmission planning and buildout, and
25 may be expressed in relation to the number

1 and total capacity of transmission lines de-
2 veloped through regional and interregional
3 planning processes, the proportion of new
4 transmission projects selected through re-
5 gional planning processes versus those ad-
6 vanced outside of such processes (including
7 local or supplemental projects), the number
8 of projects selected through competitive
9 processes, the use and outcomes of benefit-
10 cost analysis in project selection and devel-
11 opment, the frequency of stakeholder en-
12 gagement, the ratio of total investment in
13 interregional and regional transmission to
14 investment in local transmission, or other
15 related metrics.

16 (iv) Seams management and resolu-
17 tion, which shall assess the extent to which
18 the ISO, RTO, or transmission planning
19 entity identifies and addresses seams, and
20 may include the number of seams-related
21 studies initiated or completed, the quantity
22 and capacity of interties enabling cross-re-
23 gional power flows, and the frequency or
24 magnitude of congestion and price diver-
25 gence across seams.

1 (v) Greenhouse gas emissions inten-
2 sity, which shall assess, through the use of
3 methodologies specified by the Commission
4 based on input from the Administrator of
5 the Environmental Protection Agency, the
6 emissions profile of electricity delivered
7 within the service territory of the ISO,
8 RTO, or transmission planning entity in
9 the reporting year, and may be expressed
10 as the emissions intensity of delivered elec-
11 tricity in carbon dioxide equivalents per
12 megawatt-hour, or related metrics.

13 (vi) Any additional outcome-based
14 performance metrics the Commission de-
15 termines necessary to improve trans-
16 parency, affordability, reliability, equity, or
17 environmental performance of the trans-
18 mission system overseen by the RTO, ISO,
19 or transmission planning entity.

20 (3) DATA DISCLOSURE.—Each reporting entity
21 shall publish and submit to the Secretary, with each
22 scorecard published under this subsection, all non-
23 confidential underlying data supporting the metrics
24 included in the scorecard, in a machine-readable,
25 open-data format.

1 (4) INITIAL REPORTING.—Each reporting entity
2 shall publish and submit to the Secretary its first
3 scorecard not later than 6 months after the date on
4 which the Commission issues a final rule under sub-
5 section (e)(1).

6 (b) METRIC AND METHODOLOGY STANDARDIZA-
7 TION.—

8 (1) IN GENERAL.—The Commission, with input
9 from the Secretary, the Administrator, the National
10 Laboratories, and other stakeholders, where appro-
11 priate, shall standardize the metrics required to be
12 included in a scorecard under subsection (a) and the
13 methodologies for calculating such metrics, including
14 by ensuring that the definitions, data sources, and
15 calculation methodologies for each metric are uni-
16 form among all reporting entities, except as provided
17 in paragraph (2).

18 (2) EXCEPTION FOR NECESSARY REGIONAL OR
19 STRUCTURAL DIFFERENCES.—In carrying out para-
20 graph (1), the Commission may allow for a dif-
21 ference among reporting entities in metrics or meth-
22 odologies only upon issuance of a written determina-
23 tion that the difference is demonstrably necessary on
24 a regional or structural basis.

1 (3) BENEFIT-COST ANALYSIS.—In carrying out
2 paragraph (1), the Commission shall establish uni-
3 form requirements for any benefit-cost analyses to
4 be included in a scorecard under subsection (a), in-
5 cluding minimum parameters, data sources, and as-
6 sumptions to ensure comparability among reporting
7 entities and to prevent selective or undisclosed mod-
8 eling assumptions that materially affect reported re-
9 sults.

10 (c) VERIFICATION REQUIREMENTS.—

11 (1) IN GENERAL.—The Commission shall estab-
12 lish a process by which scorecards required to be de-
13 veloped under subsection (a) are verified by inde-
14 pendent evaluators to ensure accuracy, consistency,
15 and credibility prior to publication under such sub-
16 section. The Commission shall include in such proc-
17 ess—

18 (A) requirements for the approval by the
19 Commission of independent evaluators, includ-
20 ing requirements that an independent eval-
21 uator—

22 (i) possess demonstrated expertise in
23 electric transmission planning, data valida-
24 tion, engineering analysis, regulatory ac-
25 counting, or grid performance evaluation,

1 including experience with relevant mod-
2 eling tools and with data systems of the
3 Commission or the Department of Energy;

4 (ii) possess or otherwise have access
5 to technical and analytical expertise appro-
6 priate to the metrics being verified, includ-
7 ing in engineering, economics, data ana-
8 lytics, or regulatory accounting; and

9 (iii) be independent from the entity
10 being verified and have no financial, con-
11 tractual, or governance conflicts of inter-
12 est, including having no affiliation or com-
13 mon ownership with any entity responsible
14 for managing or overseeing the pension or
15 benefit funds of a reporting entity;

16 (B) procedures for auditing the assump-
17 tions and methodologies used in applying per-
18 formance metrics, including to detect selective
19 reporting and ensure alignment with Commis-
20 sion-defined protocols;

21 (C) requirements to ensure that any single
22 independent evaluator, or their parent company
23 or subsidiary—

24 (i) may not evaluate a reporting entity
25 that is a covered transmission owner more

1 than 5 reporting periods in a row, or more
2 than 15 times in any 10-year period; and

3 (ii) may not evaluate a reporting enti-
4 ty that is an ISO, RTO, or transmission
5 planning entity more than 3 reporting peri-
6 ods in a row, or more than 7 times in any
7 10-year period;

8 (D) requirements under which an inde-
9 pendent evaluator approved by the Commission
10 may verify the information in the scorecard of
11 the reporting entity, by reviewing supporting
12 documentation, conducting project inspections,
13 and applying standardized evaluation, measure-
14 ment, and verification protocols for the metrics
15 included in the scorecard;

16 (E) requirements for public disclosure of
17 the results of such verification, including any
18 adjustments to reported values, methodologies
19 used in the verification process, and justifica-
20 tions for material discrepancies; and

21 (F) a process for reviewing and refining
22 verification protocols at regular intervals, not
23 less frequently than once every 3 years, in con-
24 sultation with any relevant stakeholder advisory
25 group convened under section 5, to incorporate

1 advances in data analytics, energy system mod-
2 eling, and grid performance assessment.

3 (2) ROLE OF NATIONAL LABORATORIES.—In
4 carrying out this subsection, the Commission shall—

5 (A) collaborate with National Laboratories
6 that have the necessary expertise, in coordina-
7 tion with the Secretary, to design and publish
8 standardized verification protocols, including
9 templates, analytical tools, and calibration
10 datasets;

11 (B) utilize the technical expertise of Na-
12 tional Laboratories to assist in the training,
13 evaluation, or approval of independent eval-
14 uators;

15 (C) engage National Laboratories in con-
16 ducting selective audits or quality assurance re-
17 views of verified scorecards during initial imple-
18 mentation of the scorecard reporting and
19 verification process and implementation of any
20 subsequent updates to such scorecards; and

21 (D) consult National Laboratories during
22 periodic updates to the verification process, in
23 coordination with any relevant stakeholder advi-
24 sory group convened under section 5.

25 (d) INDEPENDENT AUDITS.—

1 (1) IN GENERAL.—The Commission, in con-
2 sultation with the Secretary, shall designate Na-
3 tional Laboratories with necessary expertise, or
4 other qualified institutions, to conduct independent
5 audits of scorecards published under subsection (a)
6 on a periodic or as-needed basis to ensure the accu-
7 racy, completeness, and integrity of reported data,
8 methodologies, and performance metrics.

9 (2) INITIATION.—An audit under this sub-
10 section may be initiated—

11 (A) at the discretion of the Secretary;

12 (B) upon identification of material discrep-
13 ancies in reported metrics;

14 (C) in response to concerns raised by a
15 stakeholder advisory group convened under sec-
16 tion 5; or

17 (D) as part of a randomized, rotating sam-
18 ple of reporting entities to support continuous
19 oversight.

20 (3) RESULTS.—The results of an audit con-
21 ducted under this subsection shall be made publicly
22 available not later than 2 months after completion of
23 the audit.

24 (e) RULEMAKING.—

1 (1) IN GENERAL.—Not later than 1 year after
2 the date of enactment of this Act, the Commission
3 shall issue a final rule to carry out this section.

4 (2) DEPARTMENT OF ENERGY SUPPORT.—The
5 Secretary shall provide technical assistance, subject-
6 matter expertise, and access to relevant data and
7 tools to the Commission in developing the rule re-
8 quired to be published under this subsection.

9 (3) INCLUSIONS.—The Commission shall in-
10 clude in the rule issued under this section—

11 (A) requirements to ensure timely and con-
12 sistent reporting, which may include require-
13 ments for data-sharing agreements, protocols
14 for data access, and other mechanisms as nec-
15 essary to facilitate the completion of scorecards;

16 (B) allowance for the use of proxies, esti-
17 mates, or approximations only—

18 (i) where direct data are unavailable;

19 and

20 (ii) if the proxies, estimates, or ap-
21 proximations are based on the best avail-
22 able data, transparently documented, sub-
23 ject to Commission review and approval,
24 and updated as improved data become
25 available; and

1 (C) requirements that all reported metrics
2 reflect a good-faith effort to provide accurate
3 representations of transmission facility and sys-
4 tem performance, subject to Commission review
5 and oversight.

6 (4) REVISIONS.—In issuing any revisions to the
7 rule under this section, the Commission shall ensure
8 that—

9 (A) such revisions are based on the out-
10 comes of any applicable technical conference
11 held under section 5;

12 (B) the period for public comment on such
13 revisions is not less than 90 days; and

14 (C) the final rule making such revisions is
15 issued not later than 180 days after the close
16 of such period for public comment.

17 (f) ENFORCEMENT.—With respect to any Inde-
18 pendent System Operator, Regional Transmission Organi-
19 zation, or covered transmission owner subject to the re-
20 quirements of part II of the Federal Power Act that is
21 required to publish a scorecard under subsection (a), a vio-
22 lation of a requirement of this section shall be considered
23 a violation of a provision of such part II for purposes of
24 section 316A of such Act (16 U.S.C. 825o–1).

1 (g) REPORT.—The Secretary shall annually publish
2 a report that compiles and analyzes scorecards submitted
3 to the Secretary under subsection (a) and, for each met-
4 ric—

5 (1) ranks the performance of reporting entities,
6 grouped by market type and governance structure;
7 and

8 (2) explains the metric and describes any
9 changes over time in the affordability, reliability, eq-
10 uity, or environmental performance of the trans-
11 mission system, as evidenced by changes in the in-
12 formation included by reporting entities in such
13 scorecards with respect to the metric.

14 (h) SCORECARD REVIEW.—Not later than 3 years
15 after the date of enactment of this Act, and every 3 years
16 thereafter, the Secretary, in coordination with the Com-
17 mission, shall conduct a comprehensive review of the im-
18 plementation of this section, including the administration
19 of the section, data collection and coordination, reporting
20 entity compliance, stakeholder engagement, and the effec-
21 tiveness of the information included in scorecards as a pol-
22 icy tool and issue a public report that includes—

23 (1) an assessment and comparison of the
24 changes over time in utility performance regarding

1 the metrics required to be included in the score-
2 cards;

3 (2) evaluation of data quality, availability,
4 methodologies, and verification practices relevant to
5 the scorecards; and

6 (3) findings and recommendations regarding
7 the scorecards provided by the technical conferences
8 held and stakeholder advisory group convened under
9 section 5.

10 **SEC. 4. ACCESSIBILITY AND PUBLIC TRANSPARENCY.**

11 (a) ESTABLISHMENT OF PUBLIC-FACING SCORE-
12 CARD PORTAL.—

13 (1) INITIATION.—Not later than 12 months
14 after the date of enactment of this Act, the Sec-
15 retary, in collaboration with the Commission and the
16 Administrator, shall initiate the establishment of a
17 public, searchable online portal housing scorecards
18 and underlying data submitted to the Secretary
19 under this Act.

20 (2) PORTAL AVAILABILITY.—Not later than 18
21 months after the date of enactment of this Act, the
22 Secretary shall establish and make available a pub-
23 lic, searchable online portal housing scorecards and
24 underlying data submitted to the Secretary under
25 this Act.

1 (b) INCLUSION IN PORTAL.—The Secretary shall
2 make public through the searchable online portal estab-
3 lished under this section each scorecard, together with the
4 underlying data associated with each scorecard, that is
5 submitted to the Secretary under this Act.

6 **SEC. 5. SCORECARD IMPROVEMENT.**

7 (a) TECHNICAL CONFERENCES.—The Commission
8 shall hold public technical conferences not less often than
9 once every 3 years to solicit stakeholder feedback on—

10 (1) the effectiveness of scorecard metrics in
11 conveying the performance of a given reporting enti-
12 ty;

13 (2) the sufficiency and quality of the data dis-
14 closed in scorecards;

15 (3) the alignment of scorecards with Federal
16 and State priorities, including affordability, reli-
17 ability, and congestion reduction of transmitted elec-
18 tricity; and

19 (4) opportunities to refine metrics in light of
20 emerging technologies, grid conditions, and energy
21 markets.

22 (b) STAKEHOLDER ADVISORY GROUPS.—For pur-
23 poses of a rulemaking under section 3 and each technical
24 conference held under subsection (a), the Commission
25 shall convene a stakeholder advisory group to provide ad-

1 vice to the Commission. Each such stakeholder advisory
2 group shall be composed of 17 members, as follows:

3 (1) 2 members representing State public utility
4 commissions.

5 (2) 2 members representing covered trans-
6 mission owners.

7 (3) 2 members representing independent power
8 producers.

9 (4) 2 members representing Regional Trans-
10 mission Organizations and Independent System Op-
11 erators.

12 (5) 1 member representing the Electric Reli-
13 ability Organization.

14 (6) 2 members representing transmission plan-
15 ning entities.

16 (7) 2 members representing ratepayer advocacy
17 organizations, each of whom shall be employed by,
18 or formally designated by, an organization the pri-
19 mary mission of which is the representation of resi-
20 dential, commercial, or industrial ratepayers in regu-
21 latory or ratemaking proceedings before State or
22 Federal authorities.

23 (8) 2 members with expertise in energy data
24 systems, grid modeling, or electricity market ana-
25 lytics, each of whom shall possess significant profes-

1 sional experience or academic qualifications, rep-
2 resenting industry, independent analytics firms, or
3 academic or research institutions, including the Na-
4 tional Laboratories.

5 (9) 2 members with expertise in energy systems
6 performance, representing academic or research in-
7 stitutions, including the National Laboratories.

8 (c) RESPONSE REQUIRED.—Not later than 60 days
9 after receiving any advice from a stakeholder group con-
10 vened under subsection (b), the Commission shall respond
11 in writing to such advice.

12 **SEC. 6. DEFINITIONS.**

13 In this Act:

14 (1) ADMINISTRATOR.—The term “Adminis-
15 trator” means the Administrator of the Energy In-
16 formation Administration of the Department of En-
17 ergy.

18 (2) COMMISSION.—The term “Commission”
19 means the Federal Energy Regulatory Commission.

20 (3) COVERED TRANSMISSION OWNER.—The
21 term “covered transmission owner” means any enti-
22 ty, other than an Independent System Operator, Re-
23 gional Transmission Organization, or transmission
24 planning entity, that—

1 (A) owns, operates, or controls trans-
2 mission facilities that are part of, or connected
3 to the bulk-power system;

4 (B) provides, or is capable of providing,
5 transmission service for the movement of elec-
6 tric energy, whether in interstate or intrastate
7 commerce; and

8 (C) if the entity owns, operates, or controls
9 transmission facilities that are not part of, or
10 connected to, the bulk-power system, the total
11 transmission capacity under peak demand con-
12 ditions of all transmission facilities owned, op-
13 erated, or controlled by the entity is 100
14 megawatts or greater.

15 (4) FEDERAL POWER ACT TERMS.—

16 (A) BULK-POWER SYSTEM; ERO.—The
17 terms “bulk-power system” and “Electric Reli-
18 ability Organization” have the meanings given
19 those terms in section 215 of the Federal
20 Power Act (16 U.S.C. 824o).

21 (B) ISO; RTO; TRANSMITTING UTILITY.—
22 The terms “Independent System Operator”,
23 “ISO”, “Regional Transmission Organization”,
24 “RTO”, and “transmitting utility” have the

1 meanings given those terms in section 3 of the
2 Federal Power Act (16 U.S.C. 796).

3 (5) GRID-ENHANCING TECHNOLOGY.—The term
4 “grid-enhancing technology” means any technology
5 the Commission determines materially improves
6 transfer capacity or interconnection efficiency, or re-
7 duces technical losses, without relying on traditional
8 wires-based transmission expansion, which shall in-
9 clude—

10 (A) dynamic line rating systems;

11 (B) advanced power flow control devices;

12 (C) topology optimization tools and soft-
13 ware-based reconfiguration technologies;

14 (D) real-time monitoring and sensing
15 equipment that improves line utilization or visi-
16 bility; and

17 (E) transformer upgrades, advanced trans-
18 mission technologies, or reactive power equip-
19 ment.

20 (6) INTERREGIONAL INTERCONNECTION.—The
21 term “interregional interconnection” means a trans-
22 mission facility or interconnection project that en-
23 ables the transfer of electric energy between two or
24 more transmission planning regions, including con-
25 nections between any of the Western Interconnec-

1 tion, the Eastern Interconnection, and the Electric
2 Reliability Council of Texas.

3 (7) REPORTING ENTITY.—The term “reporting
4 entity” means an entity required to submit a score-
5 card under this Act.

6 (8) SCORECARD.—The term “scorecard” means
7 a report required to be submitted by a covered
8 transmission owner, Independent System Operator,
9 Regional Transmission Organization, or trans-
10 mission planning entity pursuant to section 3.

11 (9) SEAM.—The term “seam” means a bound-
12 ary or interface between neighboring transmission
13 systems or grid operators.

14 (10) SECRETARY.—The term “Secretary”
15 means the Secretary of Energy.

16 (11) TRANSMISSION PLANNING ENTITY.—The
17 term “transmission planning entity” means an enti-
18 ty, other than a RTO or an ISO, that is responsible
19 for planning for the deployment of electric trans-
20 mission for a transmission planning region.

21 (12) TRANSMISSION PLANNING REGION.—The
22 term “transmission planning region” means a geo-
23 graphic area determined by the Commission to sat-
24 isfy the requirements for the scope of regional trans-

1 mission planning, as established in or in compliance
2 with the following orders issued by the Commission:

3 (A) “Transmission Planning and Cost Al-
4 location by Transmission Owning and Oper-
5 ating Public Utilities” published in the Federal
6 Register on October 24, 2012 (77 Fed. Reg.
7 64890).

8 (B) “Building for the Future Through
9 Electric Regional Transmission Planning and
10 Cost Allocation” published in the Federal Reg-
11 ister on June 11, 2024 (89 Fed. Reg. 49280).

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