Energy Regulatory Partnership Program

Between

National Association of Regulatory Utility Commissioners

and

The National Commission for State Energy Regulation

Seventh Partnership Activity

Procedures, Conditions of Setting and Financing the Electricity Network Supply Connection Fees

Overview of U.S. Transmission Network Planning, Construction and Interconnection

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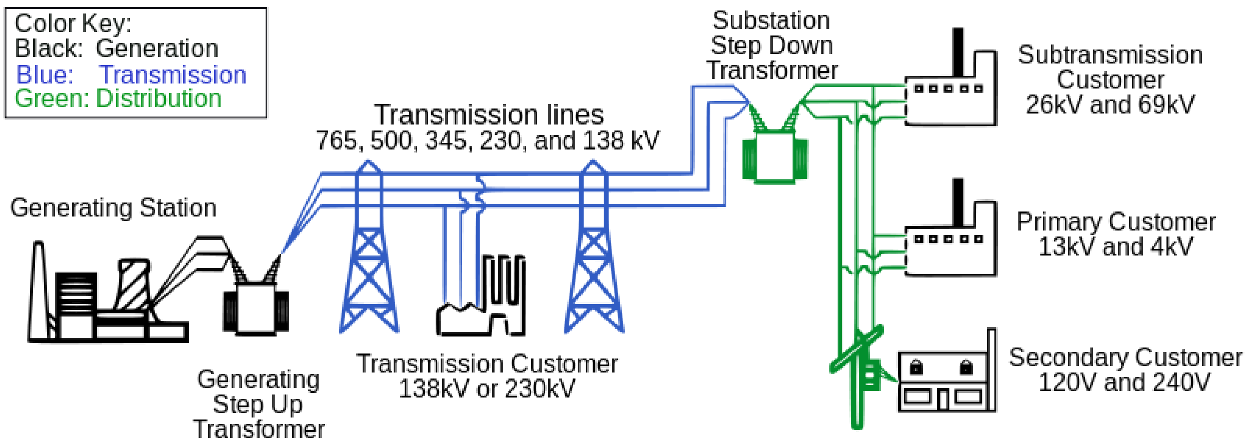
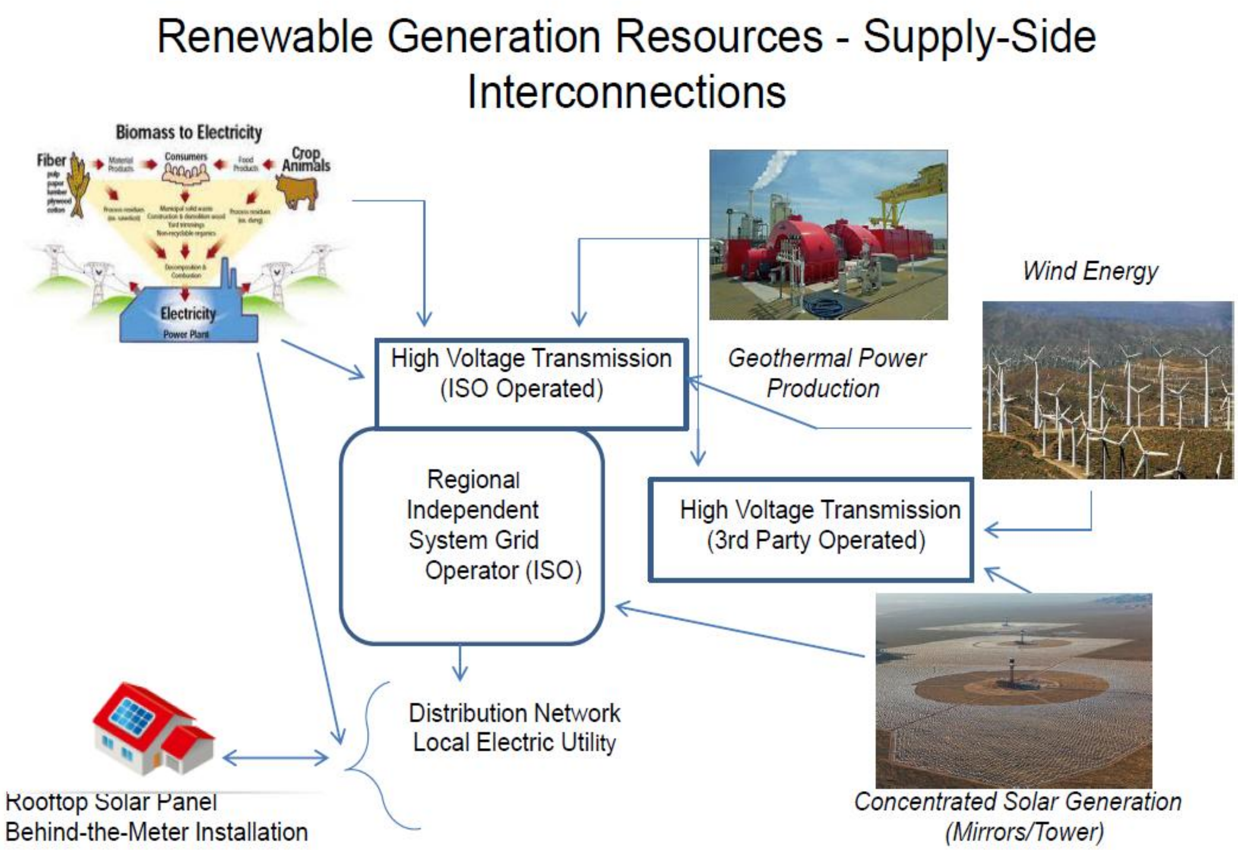
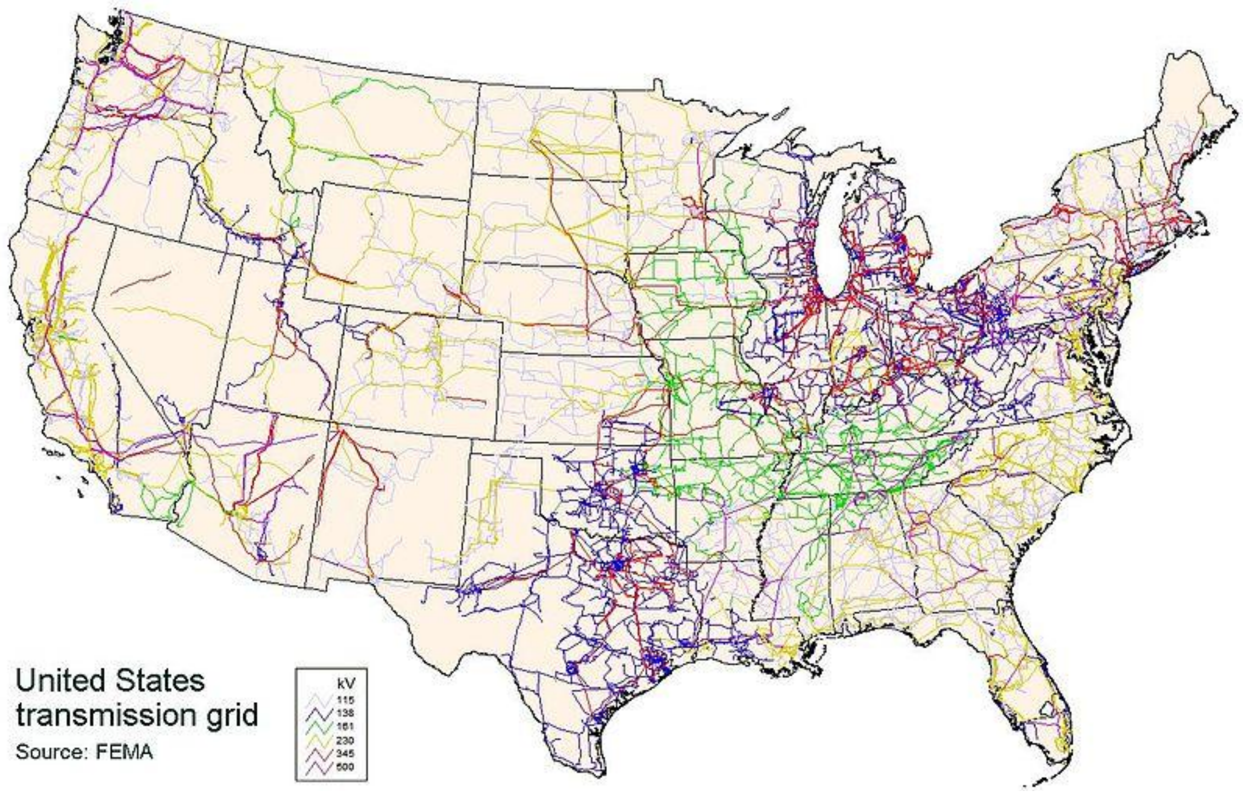
I. UNITED STATES ELECTRIC GRID –

Typical Alignment of Grid Functions

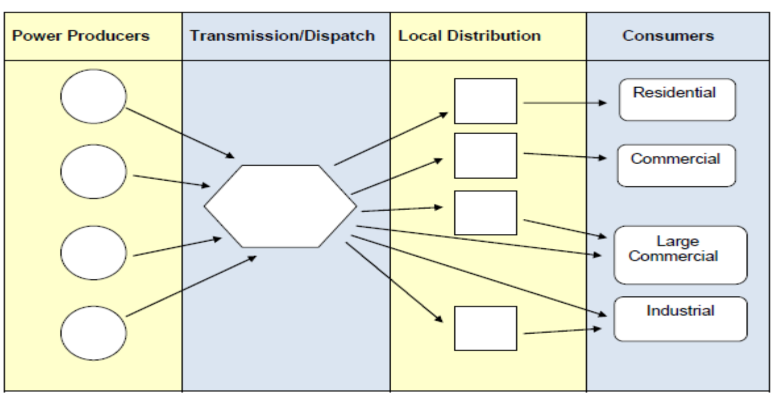




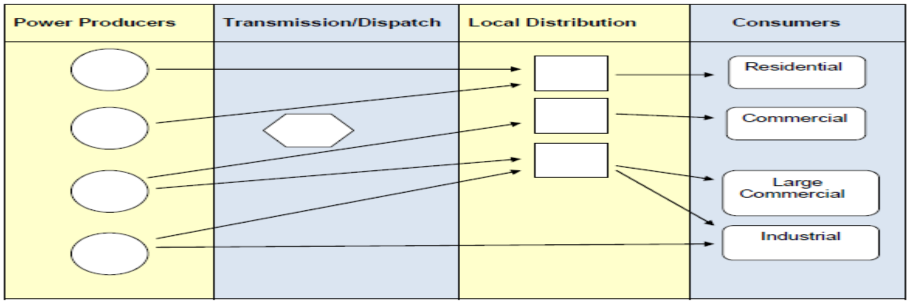
U.S. National Electric Grid – Privately Owned, Independently Operated



The U.S. Electric grid does not support a single buyer market. Instead, the market for electricity in the U.S. is one created from bi-lateral contracts allowing participants in each of the grid functions to offer a service and receive payment from participants in any other grid function. This includes direct contracts between power generation companies and large industrial end-use customers.



Single Market Buyer Model – Contractual Arrangements



Bi-Lateral Contract Model – Contractual Arrangements

II. OVERVIEW – High Voltage Transmission Service

Assets. The U.S. electric transmission grid consists of more than 200,000 miles of high-voltage transmission lines of 230 kilovolts (kV) or greater. The transmission grid does not have a unified ownership of transmission infrastructure. Ownership is shared, in the greater part, among investor-owned utilities ("IOU"), independent merchant transmission owners, and certain federal agencies that are operated as not-for-profit commercial entities, such as the Bonneville Power Administration and the Tennessee Valley Authority.

Government Regulation. Public utilities providing electric service are typically regulated by state utility commissions, including the construction of high voltage electric transmission lines that cross state borders. However, the sale of electric energy in interstate commerce for resale to end users under regulation by the U.S. Government, through the Federal Energy Regulatory Commission ("FERC"). FERC regulation extends over rates for transmission services and over various charges, including interconnect charges, billed by transmission operators or owners. FERC regulation is accomplished in a significant number of instances through FERC's regulation of regional transmission organizations ("RTO") or Independent System Operators ("IOU"). These are entities to which the public utilities surrender operational control of their transmission lines in return for guaranteed recovery of the costs the utilities incurred to build those lines and the utilities ongoing costs to maintain these lines. Should a transmission construction project be proposed in a National Interest Electric Transmission Corridor ("NEITC") FERC has secondary authority to approve the construction should the state(s) fail to timely act, act to reject the project, or condition their approval of the project in such a manner that the project will be economically infeasible or impractical to construct.

Government Policy Objectives. When considering transmission, one of the main objectives of the U.S. government over the past decade has been to eliminate congestion on the interstate transmission grid. This is being accomplished mostly through new regulations to hasten the construction of additional transmission lines. This included regulations adopted in 2006 that granted financial incentives to sponsors of new transmission projects. Since 2006, there have been 85 applications approved by the various states and FERC to construct electric transmission lines, representing over $60 billion in potential investment.

However, FERC's greater policy objectives with regard to transmission are to: a) make sure that transmission services are offered and provided on a non-discriminatory basis, and without undue preference that favors one shipper over another; and b) that all procedures and decisions involved in approving new facilities, setting rates, and allocating transmission capacity, are transparent to the public. U.S. government energy policy is designed to encourage competition, in the belief that strong competition is more efficient than government at developing energy resources and infrastructure, allocating capacity, and rationing demand.

III. TRANSMISSION INFRASTRUCTURE OWNERSHIP AND OPERATING AUTHORITY

Historically, transmission lines were owned and operated by the same company that both generated electricity and distributed the electricity to its users. Companies that provide electricity to end users are called local distribution companies. These companies are generally owned by private investors (in which case they are called Investor Owned Utilities "IOU") or owned by the government locality (village, city or county) in which the electricity is distributed (in which case they are publically owned utilities). Publically owned utilities are frequently organized as a municipal power agency, which is why they are frequently referred to as "munis".

When the distribution company assumes all three functions – generation, transmission and distribution – the company is said to be vertically integrated. A vertically integrated utility

	Generation
	Transmission
	Distribution

All functions performed by the public utility and sold as a package, at a single price.

does not separately price each of these three services. Instead, the services are bundled into one commercial product that is then billed as a single price to the consumer. In 1996, FERC issued Order No. 888. This order required that any public utility owning transmission lines operating across a state border must adopt that agency's standard form of an Open Access Transmission Tariff ("OATT"). The OATT also prohibits the utility from discriminating against any entity seeking to contract for transmission service, or discriminating between shippers in the manner in which it provides transmission services.

By requiring all transmission owners to follow the same rules when awarding capacity entitlements and follow the same rules for providing transmission services, FERC sought to both stimulate competition, while at the same time restricting that competition so that it would be fair to all parties involved. For this reason, the OATT requires these utilities to transmit power for any shipper willing and able to pay the transmission rate; as long as capacity is available, a transmission owner or operator is prohibited from turning down qualifying requests to use that capacity.

Finally, the OATT prohibits utilities from favoring their own generation and power generated or marketed from an affiliated company, when awarding or providing transmission service on its lines. Later, FERC issued Order Nos. 889 (1996), 690 (2007), and Order No. 717 (2008) in which it created standards of conduct to regulate behavior between a utility's employees serving the transmission function and employees serving the marketing function of that utility (or any marketing affiliate of that utility). These standards of conduct center around three primary rules:

1) The "independent functioning rule," that requires transmission function and marketing function employees to operate independently of each other;

2) The "no-conduit rule" that prohibits passing transmission function information to marketing function employees; and

3) The "transparency rule," that requires certain transactional information to be posted by the utility on its internet website so that the public can help detect any instances of undue preference.

The standard form OATT is a 164-page document that includes standardized forms of the service agreements that apply to various open access transmission services offered under this tariff:

Firm point-to-point transmission service;
Non-firm point-to-point transmission service;
Resale, reassignment or transfer of long-term firm point-to-point transmission service;
Network integration transmission service; and
Network operating agreement

Open Access Transmission Tariff

<u>General Provisions</u>
- Initial Allocation and Renewal Procedures
- Alternate procedures for Requesting Transmission Service
- Billing and Payment
- Required Regulatory Filings
- Force Majeure and Indemnification
- Creditworthiness
- Dispute Resolution Procedures

Open Access Transmission Tariff

<u>Point-to-Point Firm/Non-Firm Transmission Service</u>
- Nature of service – priority, curtailment, scheduling
- Customer responsible for costs of facility additions
- Length of service
- Customer obligations
- Procedures for arranging service – application, deposit, signed service agreement, extension of time for service start date

Open Access Transmission Tariff

<u>Point-to-Point Firm/Non-Firm Transmission Service</u>
System Impact Study and cost reimbursement
Facilities Study procedures and Study modifications
Due Diligence required in completing new facilities
Penalties for failing to meet Study deadlines
Procedures if Transmission Provider is Unable to Complete Construction of New Transmission Facilities

Open Access Transmission Tariff

Provisions Relating to Transmission Construction and Services on Systems of Other Utilities
Changes in Service Specifications
Metering and Power Factor Correction at Receipt/Delivery Points
Compensation – Transmission Service/New Facilities and Re-Dispatch Costs

Open Access Transmission Tariff

<u>Network Integration Transmission Service</u>
Designation of Network Load
Required Studies
Load Shedding and Curtailments
Rates and Charges – monthly demand charge / re-dispatch Charge, stranded cost recovery
Operating Arrangements

Open Access Transmission Tariff

<u>Ancillary Services</u>
Scheduling, system control and dispatch service
Reactive supply / voltage control from generation sources
Regulation and frequency response service
Energy imbalance service
Operating Reserve – spinning reserve service
Operating Reserve – supplemental reserve service
Generator imbalance service

Open Access Transmission Tariff

Other Topics
Standard forms of various service agreements (pages 1091 through 1255 of standardized OATT
Method to assess available transfer capability
Method for completing system impact study
Annual revenue requirement for network integration transmission service
Procedures for addressing parallel flows
Transmission planning process
Creditworthiness procedures

Order No. 889 also adopted federal rules that created an Open Access Same-Time Information System ("OASIS"). Each public utility providing transmission service under an OATT, and each non-public utility receiving transmission service under an OATT must create and maintain an OASIS with respect to their respective transmission systems. The purposes of the OASIS are to provide all actual and potential open access transmission customers with identical information about available transmission capacity, prices, and other information that will enable them to obtain open access, non-discriminatory transmission services. Order No. 889 also imposed standards and communication protocols to provide for the electronic dissemination of this information. This includes standardized displays and formats to appear electronically on each company's OASIS webpages.

Open Access Same-Time Information System (OASIS)

Purpose: to communicate through electronic means information that will enable actual and potential transmission customers to choose and receive open access, non-discriminatory high voltage transmission service.

- Communicates information on availability of transmission capacity
- Communicates information on capacity pricing
- Standardizes OASIS displays (content) and formats (appearance) for all systems

Over the same approximate time period, some state utility commissions began requiring vertically integrated utilities to unbundle their services. These unbundling efforts were done to allow end-users of electricity to choose their energy commodity supplier (called "retail choice"). State authorities believed that retail choice would create competition between generation companies, resulting in lower energy commodity costs. Some states, such as California, required public utilities to sell their company-owned generation assets to independent generation companies. However, since many residential customers do not want to choose their own electricity supplier and are content with the utility's prior merchant role, the state utility commissions require these distribution companies/transmission owners to remain a supplier-by-default for end users not electing to choose their own commodity supplier.

From this:

	Generation
	Transmission
	Distribution

All functions performed by the public utility and sold as a package, at a single price.

To this:

	Generation
Owned / operated by independent 3rd party	

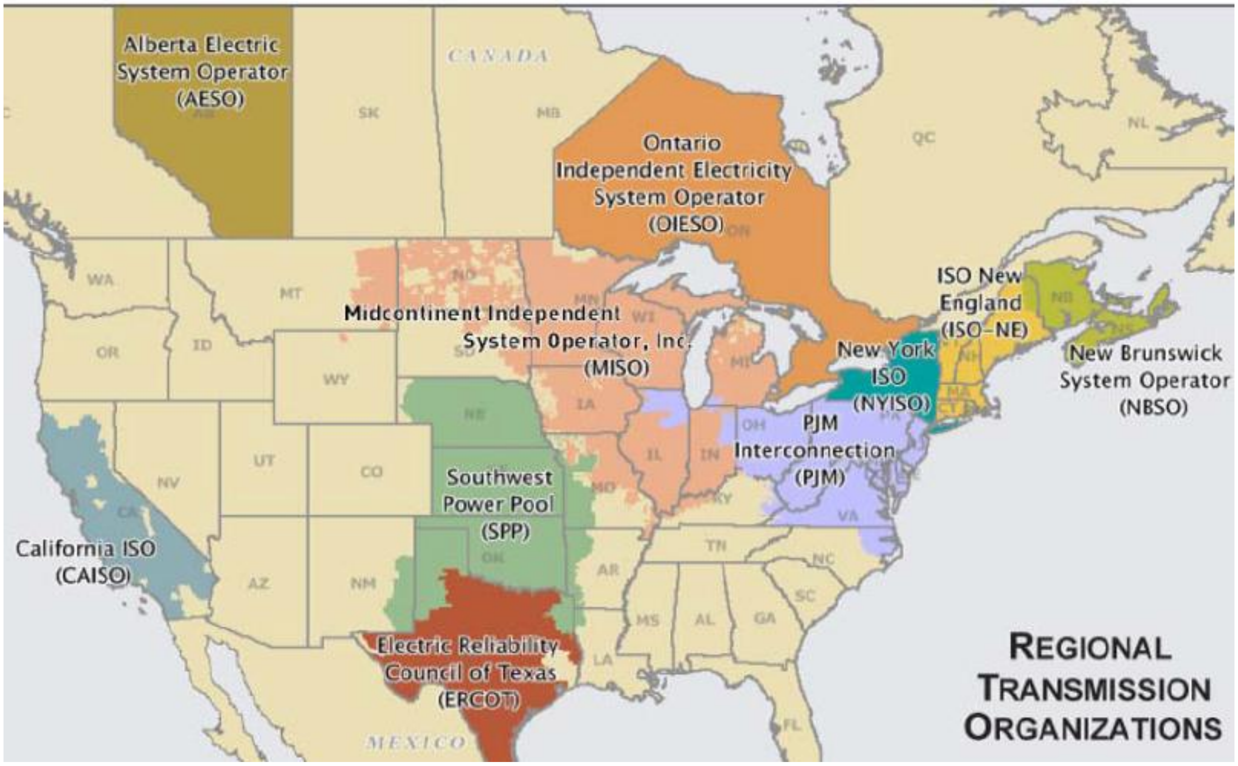
	Transmission
owned by utility / operated by independent 3rd party entity	

	Distribution
owned and operated by utility	

FERC concluded that the OATT, by itself, would, in some instances, not be enough to deter anti-competitive market behavior by transmission owners. FERC decided that anti-competitive behavior would be less likely to occur if operational control of transmission lines were to be surrendered by the transmission owner to a neutral, independent third party entity. For this reason, FERC urged the creation of Independent System Operators to manage, under FERC's oversight, the operation of the utilities' transmission lines. Subsequently, in Order No. 2000 FERC encouraged the creation independent third-party entities to operate transmission grids on a regional basis throughout North America, including in Canada. These entities are either Regional Transmission Organizations or Independent System Operators.

To offer an incentive to transmission owners to yield operational control of their transmission lines to these third-party entities, FERC provided that upon transferring operational control, the risk of under-recovering the cost of owning and maintaining these lines would be eliminated. This is done by the third-party entity collecting a "grid access charge" from shippers across the RTO/ISO's control area. The revenue from the grid access charge is allocated to the participating transmission owners pursuant to a formula approved by FERC on a case-by-case basis. The grid access charge is adjusted annually to compensate for any cost under- or over-recovery during the preceding year. In the U.S., the RTOs and ISOs are referred to as Public Utility Transmission Providers and the utilities owning, but not operating, these lines are referred to as Public Utility Transmission Owners.

RTOs or ISOs are now established in the larger U.S. energy market areas, which generally coincide with areas served by IOUs. Areas served by municipal power companies and rural electric cooperatives typically are outside the control areas of these third-party entities, although these municipal power companies may participate in regional planning for load balancing and reliability purposes.



U.S. and Participating Canadian Regional Transmission Organizations and Independent System Operators

UNITED STATES	
Third Party Entity	**Geographic Control Area**
California Independent System Operator (CAISO)	California, excluding Sacramento County and other areas served by municipal power companies
Electric Reliability Council of Texas (ERCOT)	Texas, excluding the Northern Panhandle area and portions of NE/SE Texas
Midcontinent Independent System Operator (MISO)	North Dakota, South Dakota, Wisconsin, Iowa, Missouri, Illinois, Indiana, Michigan
Southwest Power Pool	Nebraska, Kansas, Oklahoma and Northern Panhandle, NE areas of Texas, SE New Mexico
PJM Interconnection (PJM)	Ohio, Virginia, Maryland, Pennsylvania, New Jersey, Delaware, and small portions of North Carolina, Illinois and Indiana
New York Independent System Operator (NYISO)	New York
Independent System Operator New England (ISO-NE)	Connecticut, Maine, Massachusetts, New Hampshire, Vermont and Rhode Island

CANADA	
Alberta Electric System Operator	Province of Alberta; subject to regulation by the Alberta Utilities Commission
Ontario Independent Electricity System Operator (OIESO)	Province of Ontario; subject to regulation by the Ontario Energy Board
New Brunswick System Operator (NBSO)	Province of New Brunswick; subject to regulation by the New Brunswick Energy and Utilities Board

In addition to the investor owned utilities, independent non-utility transmission companies (each called a "Transco") participate in the transmission market. These companies compete with traditional utilities to construct and own transmission upgrades requested by RTOs and ISOs. They may also be formed as a partnership of multiple developers and utilities to construct and operate transmission facilities needed to deliver power into the grid from a specific remote generation project (such as a large scale wind or solar project.) These independent transmission companies frequently provide what is called merchant transmission service, which is an arrangement in which the Transco constructs and operates transmission lines and assumes the risk of paying for this construction and operation by marketing the capacity; grid access charges are not available to fund this cost recovery.

FERC has pricing rules under which Transco's may qualify to charge transmission rates that are the product of negotiations between the Transco and its shippers, rather than rates that are derived solely from the Transco's cost of providing its transmission services. Merchant transmission services may also qualify for certain pricing incentives allowed by the U.S. Government to stimulate the development of additional transmission capacity across the U.S. grid. One such pricing incentive is an increase in the Transco's rate of return on the equity it invested in the project.

The largest independent transmission company in the U.S. is ITC Holdings Corporation (formed in 2003), with approximately 15,000 circuit miles of high voltage transmission line that, serves a peak day load of 25,000 megawatts ("MW"). Over the past 6 months, ITC filed in various states for approval to merge with Entergy, another energy company that owns and operates high-voltage transmission lines. If this proposed merger goes forward, the merger will double the number of circuit miles of transmission line under ITC's ownership.

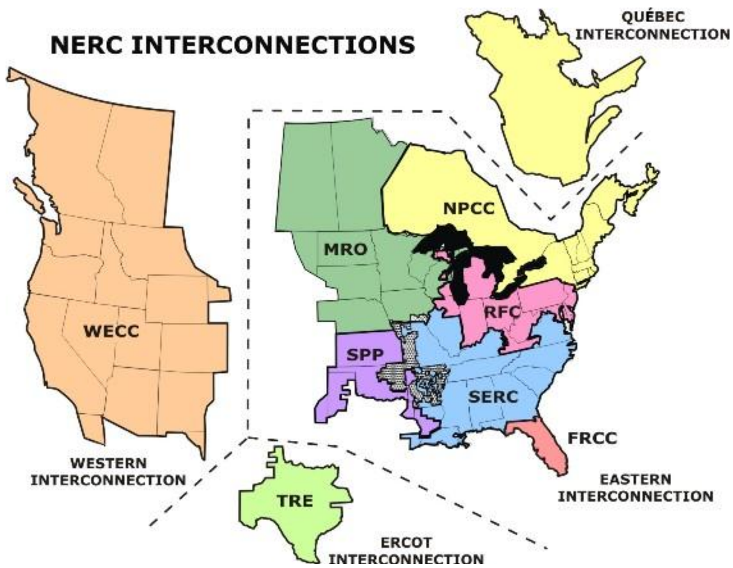
III. RELIABILITY AND PLANNING

Reliability

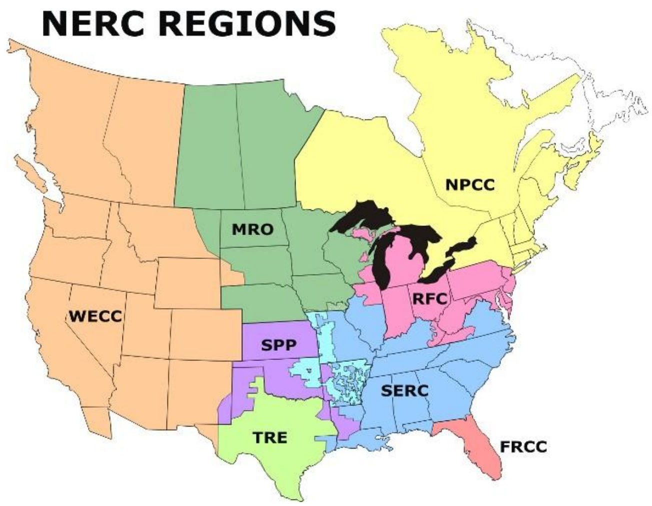
RTOs and ISOs assume the primary role in scheduling and dispatching power across the U.S. transmission grid and for planning grid improvements. However, planning for and monitoring grid reliability is the responsibility of the North American Electric Reliability Corporation ("NERC"). NERC annually evaluates the seasonal and long-term reliability of the grid, monitors the daily flow of energy across the grid, and imposes reliability standards to be followed by RTOs and ISOs in planning and operating their control areas. NERC has legal authority to impose penalties for violations of its standards, up to $1 million per violation, per day.   NERC's geographic areas of responsibility include the continental area of the U.S., all of Canada, and the northern portion of Baja California, Mexico.

For purposes of monitoring the grid, each transmission of power across the grid is given a NERC E-Tag. The E-Tag is a transaction summary created by the marketer or scheduler of the power, describing the physical path of the energy flow, identifying all participants to the transaction, and providing other descriptive data. The E-Tag is posted on the internet, where it is simultaneous delivered electronically to RTOs, ISOs and other participants to the transaction.

Regional transmission operators are able to use E-Tag data to help balance their control areas, avoid or circumvent congestion, and to compensate for equipment outages. E-Tags are shared electronically in real time, which allows the E-Tag to be electronically approved or rejected by the transmission operator. If the E-Tag is rejected, the transaction is not allowed on the grid. Approved E-Tag data is also directed in real time to the Eastern Interconnect and/or Western Interconnect, where the data is applied to create a real-time virtual study model of these Interconnects.



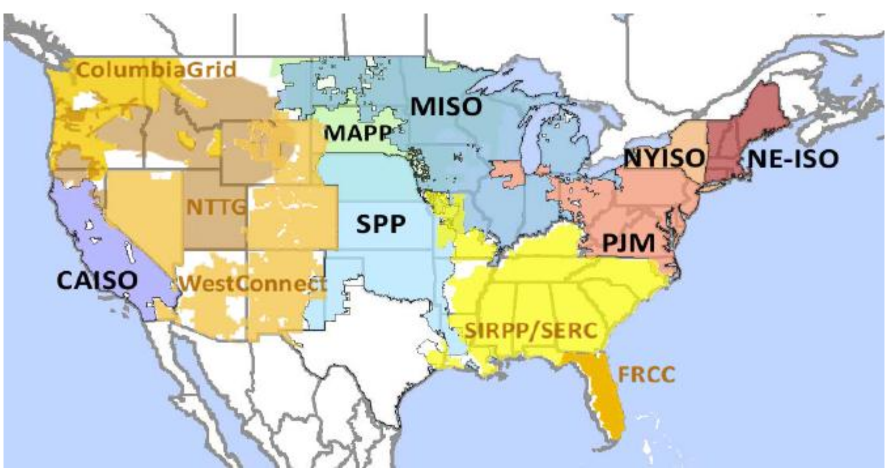
Integrated Reliably Planning Areas (NOT for shared operational control)



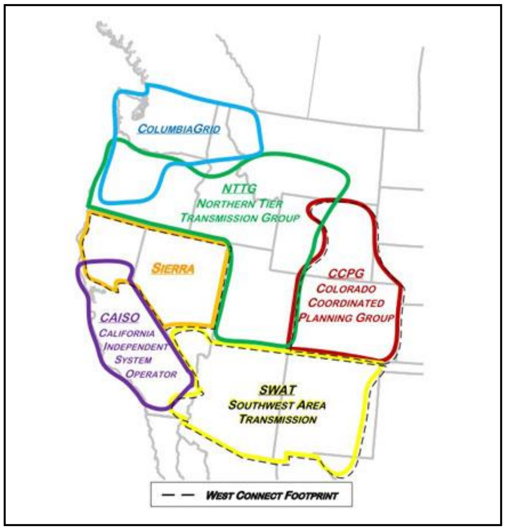
WECC = Western Electricity Coordinating Council TRE = Texas Reliability Entity
MRO = Midwest Reliability Organization SERC = SERC Reliability Corporation
SPP = Southwest Power Pool FRCC = Florida Reliability Coordinating Council
RFC = ReliabilityFirst Corporation NPCC = Northeast Power Coordinating Council

Planning

Individual RTOs and ISOs typically have intertie agreements with adjacent control area operators that provide for the export and import of power. These intertie agreements are used to maintain load balancing and stability. For this reason, the U.S. is divided into regional planning areas that are larger than individual control areas of the various RTOs and ISOs. Planning for grid interconnections with new generation resources and merchant transmission projects and for control area transmission enhancements is undertaken within these regions and inter-regionally when power is proposed to flow outside the planning region. The map below depicts regional planning areas within the U.S.



In FERC Order No. 1000 (2011), FERC adopted universal planning standards to be followed by all U.S. regional planning entities in connection with different types of transmission grid upgrades. The purposes behind having universally applicable planning standards include the ability to ensure that regional planning by a public utility transmission provider for transmission capacity additions is conducted in a transparent and non-discriminatory manner, and that capacity additions are made without undue preference.



West Connect – Regional Planning Transmission Provider for the Southwestern U.S. (6 sub-regions)

Western U.S. Sub-Regional Planning Areas

The needs addressed by these transmission upgrades include: a) improvements needed so that grid operations do not violate a NERC reliability standard; b) responding to increased load; and c) responding to new transmission requirements imposed by public policy needs. Public policy needs refers primarily to the renewable resource portfolio standards adopted in most U.S. states (which are typically being met through wind and solar generation.) Planning takes into account the development and interconnection of merchant transmission projects and the resultant introduction of large amounts of power into the grid. In this situation, grid upgrades may be required to relieve potential congestion. Unlike merchant transmission projects, the costs associated with the projects evaluated and approved through this planning process are allocated regionally and collected through grid access charges. In merchant transmission projects, project costs are recovered only from the shippers utilizing the project's capacity. Thus, the financial risk of the project remains with the project's investors.

Order No. 1000 requires regional planning entities to evaluate non-transmission options before approving new transmission facilities. Non-transmission options include such things as distributive generation, pump storage, demand-side management techniques and energy efficiency. Although information concerning a merchant transmission project (meaning a transmission project for which costs will not be recovered through the grid access charge) needs to be shared with the regional planning entity, the merchant project is not subject to evaluation and approval by that entity.

Federal rules now require adjacent planning regions to coordinate and share the results of their respective regional transmission plans. The primary purpose of this coordination is to identify and jointly evaluate possible inter-regional transmission facilities that would be more efficient that separate regional transmission proposals. There is no requirement to coordinate across adjacent planning regions for transmission facilities to be located in a single planning region. The planning process set out in Order No. 1000 has the following major components:

1. Develop a regional transmission plan that, among its other attributes, identifies new transmission capacity needs (for example, capacity needed to address future needs associated with reliability, load growth, congestion relief, and managing imbalances).

2. Identify the criteria under which an entity is determined to be eligible to become an applicant to provide capacity to meet one or more needs shown in the regional transmission plan. These criteria address the technical expertise of the entity in its ability to construct, own, operate and maintain transmission facilities.

3. Identify the information that a prospective transmission developer must submit in support of a transmission project the developer proposes for inclusion in the regional transmission plan.

4. Describe the process and identify the criteria for evaluating projects for selection in the regional transmission plan. This must include a public and competitive solicitation process in which the transmission provider (RTO/ISO) identifies transmission needs, including those associated with public policy demands, and obtains proposals to meet those needs from eligible transmission developers.

5. Describe the conditions under which the transmission provider will re-open the regional transmission plan to solicit projects to substitute for its prior selections.

6. Describe cost allocation procedures under which new participating transmission owners will recover project costs. This includes restricting assignment of costs to those benefiting from the project. Cost may be allocated uniformly or in differing percentages across the transmission providers control area, or inter-regionally for cross-border transmission facilities. Cost allocation is to be made by following the six principles listed below:

   i. Cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities, in a manner that is at least approximately equal to the estimated benefit received.

   ii. Those that receive no benefit from the transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the facility costs.

   iii. If a cost-benefit test is used to evaluate the need for new facilities, the benefit-to-cost ratio used as a threshold for approval cannot exceed 1.25, unless the region makes a showing to FERC that justifies a higher ratio.

iv. Costs must be allocated solely to customers within the transmission planning region, unless an entity outside the planning region, or another transmission planning region voluntarily agrees to assume a portion of those costs.

v. The cost allocation method and data required in order to determine benefits and identify beneficiaries from the new facilities must be transparent (public) with adequate documentation to allow an interested person to determine how they were applied to a proposed transmission facility.

vi. A different cost allocation method may be used within the transmission planning region for transmission facilities proposed for different purposes (such as congestion relief, to satisfy public policy needs, or for reliability purposes.) This principle is primarily to allow use of flexible cost allocation methods that will make the construction of transmission capacity in support of new renewable energy generation projects financially feasible.

In 2003, FERC issued Order No. 690 in which it required public utility transmission providers to provide generator interconnection service on a non-discriminatory basis. This order also clarified that as a general rule, the generator pays for facilities on its side of the interconnection point. The cost of upgrades to the transmission provider's transmission system is initially paid by the generator; however, the transmission provider then refunds that amount during the initial five years following commercial operation of the generator.

To ensure that these interconnects will be provided on a non-discriminatory basis, FERC created standardized interconnection procedures to be followed by all public utility transmission providers. FERC also created standardized generator interconnection agreements and required all of transmission providers to use this standardized agreement. The standardized procedures and interconnection agreements differentiate between small generators (up to 20 MW) and large generators (above 20 MW). To encourage the connection of renewable generation (which typically is in projects sized at 20 MW or less), the small generator interconnection procedures provide for speedy (fast track) handling of the following:

• Requests by pre-certified generators of 2 MW or less to interconnect with a low voltage electric system obtain fast track handling.

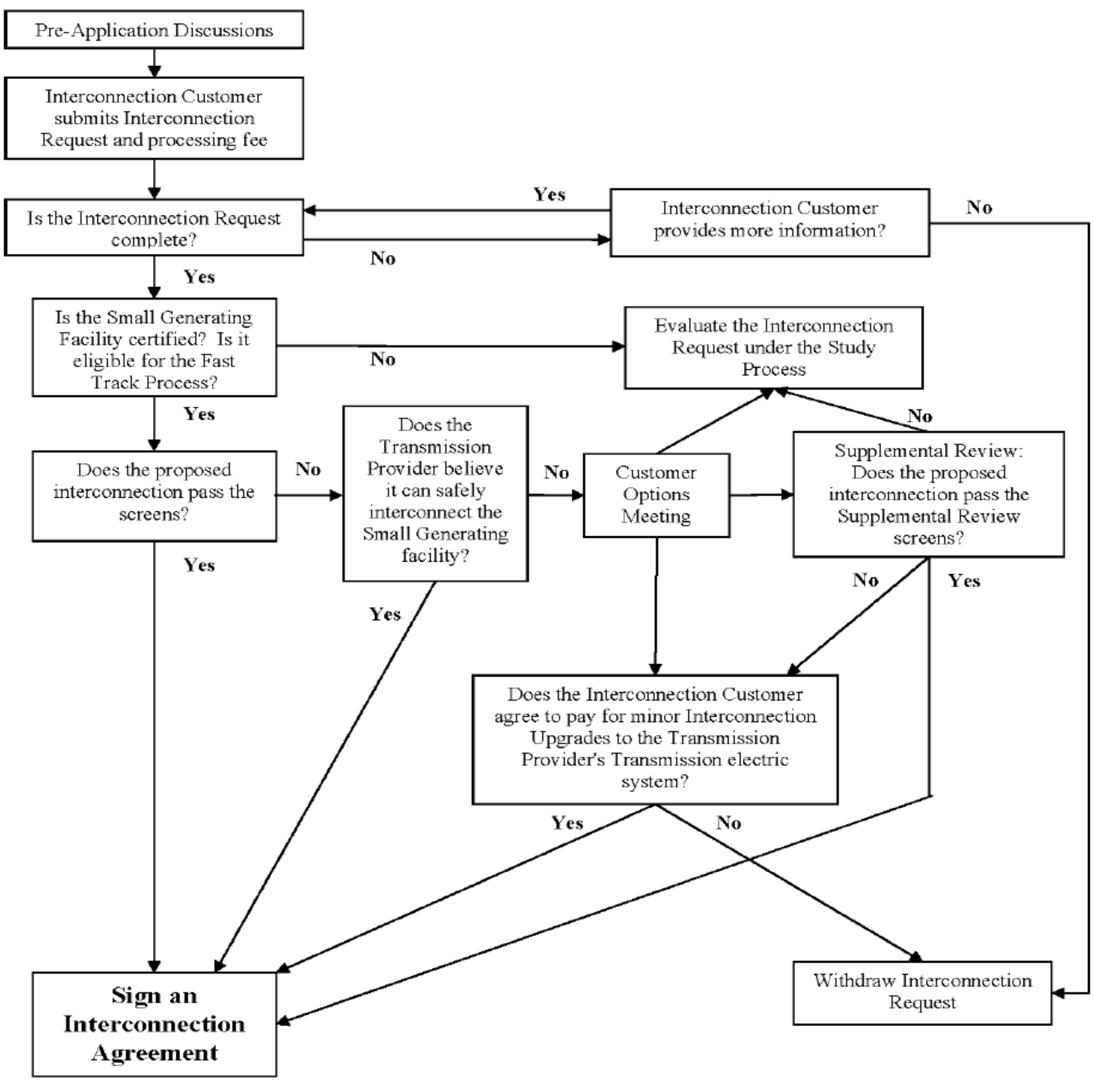
• Requests by generators between 2 and 10 MW to interconnect with a low voltage electric system – expedited timing, but not fast track handling.

• Requests by small generators to interconnect to a an electric system of 69 kV or higher, and requests for generators larger than 10 MW to connect to a low voltage electric system - expedited timing, but not fast track handling.

In January 2013, FERC proposed to modify the 2 MW threshold upward to 5 MW, subject to the following operating characteristics:

Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on ≥ 600 Ampere Line and ≤ 2.5 Miles from Substation
< 5 kilovolt (kV)	≤ 1 MW	≤ 2 MW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV	≤ 4 MW	≤ 5 MW

Flow Chart for Interconnecting a Certified Small Generating Facility Using the "Fast Track Process"



The flow chart on the preceding page records the various steps within the fast track process. If the series of boxes on the far left of the flow chart are consistently answered "yes", the process may take as little as 50 days. If supplemental review and more information is required, the entire process, up to the signing of the interconnection agreement may take up to 105 days. One of the more critical features of the standard process for small generation interconnections is the position the interconnection request takes in the queue of similar requests. Queue position helps determine the cost responsibility of the generator for transmission grid upgrades necessary to accommodate the request. Later in time requests pay only those upgrade costs that are incremental to the upgrades preceding its request.

Three sequential studies may be required (performed by the transmission provider at the generator's expense). These are:

- Feasibility Study – to identify any potential adverse system impacts that would result from interconnecting the small generating facility (the Transmission Provider may decide to omit this study). A deposit is to be paid by the interconnection customer equal to the lesser of 50% of a good faith estimate of the cost of the study or $1,000;

- Impact Study – to identify and detail the electric system impacts that would result if the proposed small generating facility were interconnected without project modifications or electric system modifications. The system impact study also evaluates the impact of the proposed interconnection on the reliability of the electric system. If the feasibility study shows that no system impact study is required, but the proposed interconnection will have potential adverse impacts on the downstream electric power distribution system, a distribution system impact study is required. A deposit of the good faith estimated costs for each impact study may be required from the interconnection customer.

- Facilities Study – to specify and estimate the cost of the equipment, engineering, procurement and construction work (including the cost of general overhead expenses) needed to implement the facility upgrades shown by the conclusions reached in the impact study or studies. The design work for any required interconnection facilities or transmission grid upgrades is to be performed under the facilities study agreement entered into between the interconnection customer and the transmission provider. A deposit of the good faith estimated costs for the facilities study may be required from the interconnection customer.

Upon completion of the facilities study and after the interconnection customer has agreed to pay for interconnection facilities and transmission upgrades, the transmission provider has five days within which to provide the interconnection customers with the standard form small generator interconnection agreement.

Large generator interconnections have a similar, but greatly expanded and more time consuming process.

Illustrative Interconnection Process (CAISO)

To show how new generation interconnection requests are responded to by grid operators, an example is given below of the alternative study processes that may be selected by an electric generators when applying for an interconnection with the California Independent System Operator ("CAISO"). The studies initially determine the feasibility of a project's design, the impact of the project upon grid stability (balance), and the impact of the project upon grid reliability. For example, a project may be designed properly to allow movement of the energy along a selected path, but in so doing, it may cause congestion elsewhere on the grid, cause the grid to violate a NERC reliability standard, or increase the likelihood that the grid may become imbalanced. The study process tests the design against these and other factors.

Alternate Study Processes

Cluster Study Process (most commonly used method)

1. Interconnection requests are to be provided by project sponsors only between April 1 and April 30 of each year. All requests received during this time are grouped by location into a cluster study group. There is no priority position given to those who submit their request earlier in the month; a projects clustered together are ranked together for process timing.

2. Each project receives its own interconnection study, a process that take approximately 420 days. The project sponsor must submit a study deposit of $50,000 plus $1,000 per megawatt ("MW") of power, up to a maximum of $250,000. The CAISO study will begin in July.

Independent Study Process

1. The interconnection request may be provided at any time of the year. Projects are placed into a processing queue and considered in the order received. The project must demonstrate through a flow impact test or a short circuit test that it is electrically independent of other projects in the queue.

2. The project's proposed commercial online date is achievable and will not accommodate use of the cluster study process.

3. The same study deposit that applies to the cluster study process is required.

4. The project will be financially responsible for network upgrades and must post financial security for network upgrades.

Fast Track Study Process

1. The interconnection request may be provided at any time of the year. Projects are placed into a processing queue and considered in the order received. The project must demonstrate through a flow impact test or a short circuit test that it is electrically independent of other projects in the queue.

2. The fast track study process is limited to projects of no larger than 5 MW. FERC's standardized Small Generator interconnection Agreement is to be signed.

3. A $500 non-refundable processing fee and a $1,000 study deposit are required. The project must reasonably anticipate that no grid transmission upgrades are necessary. Both the CAISO and the public utility owning the transmission lines must determine that the generation may be interconnected safely, reliably and is consistent with power quality standards.

10 Kilowatt (kW) Inverter Study Process

1. Available only for inverter-based small generating facilities no larger than 10kW. Facilities must either: a) meet the codes, standards and certification requirements of the Small Generator Interconnection Procedures imposed by FERC; b) pass the design review of the public utility owning the transmission lines; or c) been tested by that public utility and the public utility is satisfied that the facilities are safe to operate.

2. A non-refundable processing fee of $100 must accompany the interconnection application. This application is a unified document that also includes the simplified Small Generator Interconnection Agreement.

CAISO Timeline to Initial Synchronization ("IS") and Date of Commercial Operation ("COD")

A. 210 days before IS/COD: Sponsor submits completed initial contact request form, project details form, issued for construction electrical drawings (one-line diagrams), metering scheme overview and executed Small (up to 20 MW) or Large (more than 20 MW) Generator Interconnection Agreement.

B. 180 days before IS/COD: Sponsor submits its internet IP and ISP static address, an initial meter documentation package, a communication block diagram and, with respect to wind and solar projects, a site footprint template and meter station location template.

C. 120 days before IS/COD: Sponsor to provide information request sheets to allow completion of a participating generator agreement (with templates for 2 schedules) and to complete a meter service agreement. The sponsor is also to provide a completed generator resource data template.

D. 30 days before IS/COD: Sponsor to provide executed participating generator agreement and meter service agreement, letter accepting appointment of a scheduling coordinator, the final version of the generator resource data template and various control and protection documentation. A final metering package is submitted, along with the sponsor's control room 24 hours a day, 7 days a week contact information. A telemetry and meter validation test is scheduled and electronic security agreements are signed for meter devices.

E. 10 days before IS/COD: Metering and telemetry testing is to be completed by this date. An interconnection approval letter is to be received from the public utility owning the transmission lines. An email is sent to the generation resource owner providing notice of the planned synchronization date.

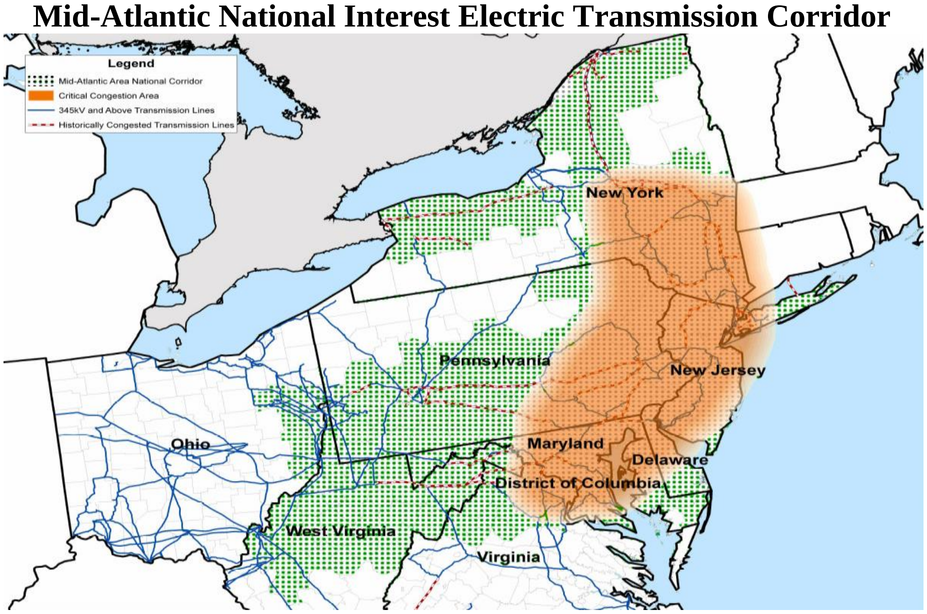
F.   1 day before IS/COD: CAISO system operations grants approval for synchronization. The project's scheduling coordinator contacts the CAISO with 24 hour notice of the upcoming synchronization. The scheduling coordinator also gives notice to the CAISO's real time generation desk.

G.   Date of Commercial Operation: Metering and telemetry certificates of compliance are issued. The public utility owning the transmission lines provides a letter approving commercial operation of the interconnection.   The generation owner provides a date of commercial operation notification letter.

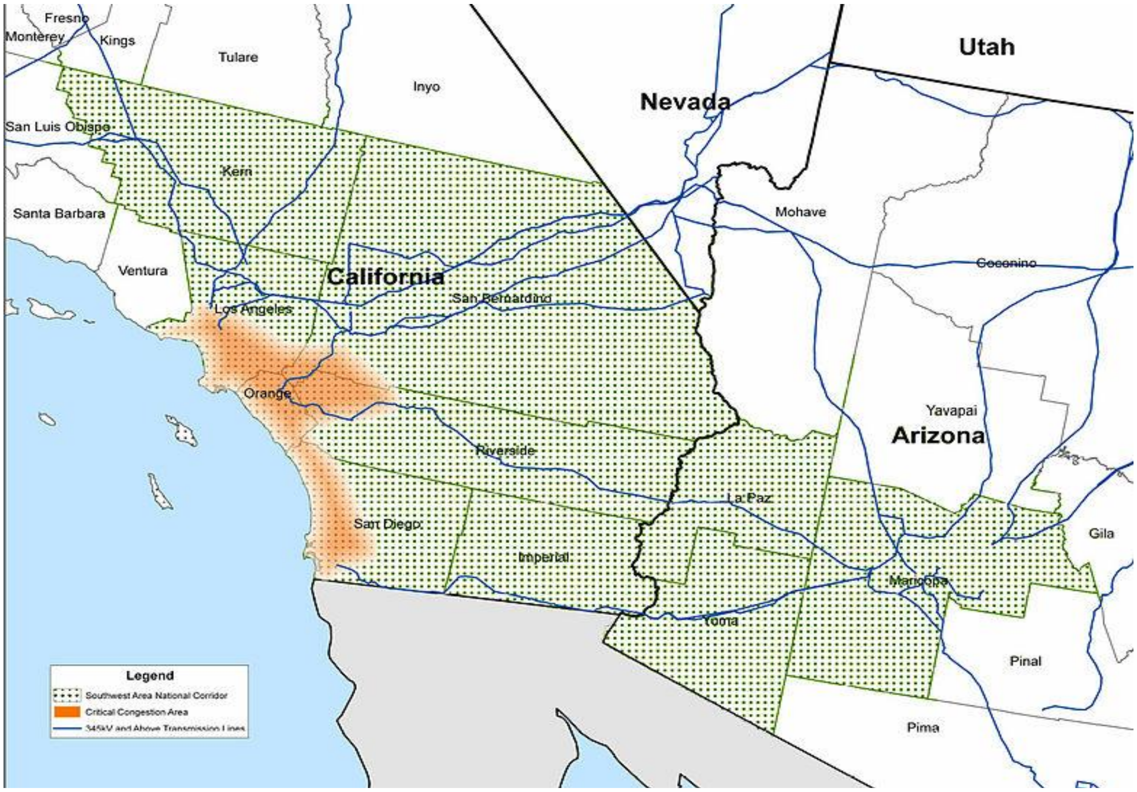
IV.   APROVAL TO CONSTRUCT AND OPERATE NEW TRANSMISSION FACILITIES

In the past, approval to construct and operate high voltage transmission lines was given by state, and not federal, regulatory agencies, unless those lines crossed a state boundary. Dissatisfaction by the U.S. Government with state agency actions that stalled needed transmission grid improvements led to a change in the law, in 2005. Since then, the U.S. Department of Energy may designate "National Interest Electric Transmission Corridors" which are transmission paths deemed critical to the functioning of the national electric grid. The federal government may assume the authority to approve transmission facilities in these corridors, when state action is either delayed or denies such approval. To date the U.S. DOE has approved two of these corridors: one in the Southwestern U.S., including Southern California and the solar and wind resource areas of California and Arizona's deserts; the second in the Mid-Atlantic regions of the U.S. Both corridors include areas of high demand and critical congestion.

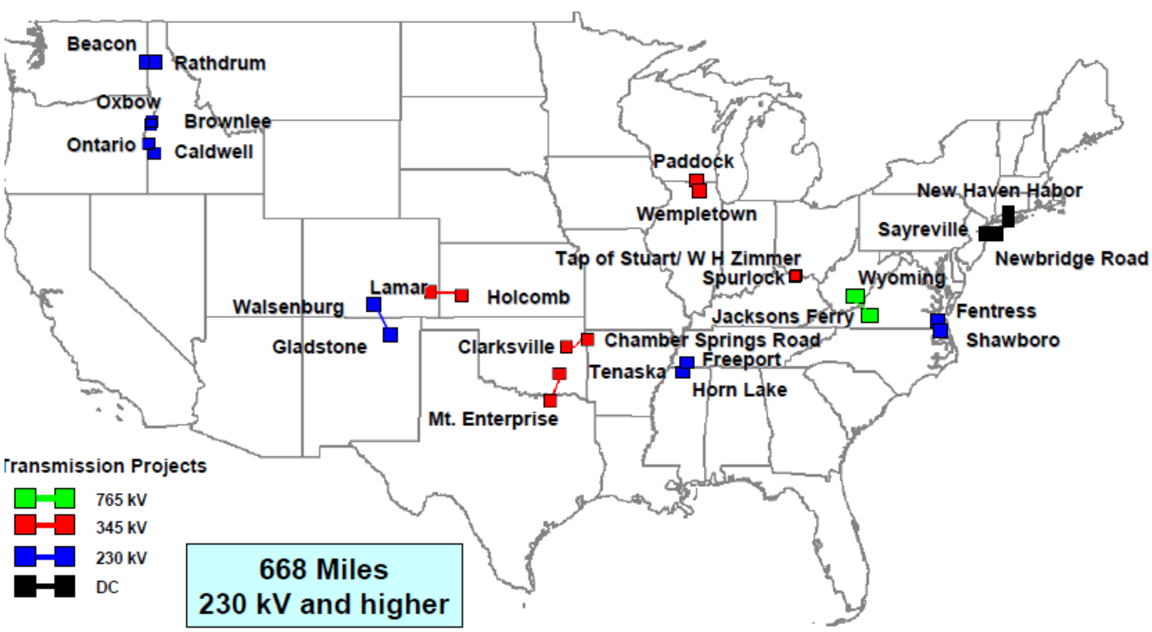
Mid-Atlantic National Interest Electric Transmission Corridor



Southwest Area National Interest Electric Transmission Corridor



Although FERC has not yet invoked this authority to approve construction and operation of new transmission lines in these corridors, since 2000, 14 interstate high voltage transmission projects have been constructed pursuant to state authorizations, shown in the map below:



Recently, FERC adopted final rules to govern its permit process for new high voltage transmission line projects located in NIETC corridors. FERC is required by law to act upon a permit application within one year of the date of its filing. Therefore, its process is segmented into two parts – a pre-filing segment (largely devoted to considering environmental compliance needs), and a post-filing segment (technical, policy and rate analysis).

In order to issue a permit approving construction of a corridor transmission project FERC must find that the proposed project:

- Is eligible for a construction permit issued by the Commission;.
- Is located in a National Corridor designated by the Department of Energy;
- Will be used in interstate commerce;
- Is in the public interest;
- Will significantly reduce transmission congestion and protect and benefit consumers;
- Is consistent with sound national energy policy and will enhance energy independence; and
- Will maximize the use of existing towers or structures, to the extent reasonably and economically possible.

Significantly, FERC concluded in Order No. 689 (2006) that project costs and financing of the project are not subjects to be considered in the permit proceeding. Thus, nothing has been said to date by FERC regarding adequacy of financing, cost allocation or rate design. FERC's permit process is summarized as follows:

Initial Consultation

Prior to a company requesting the initiation of the pre-filing process, company representatives are required to meet with Commission staff to explain the proposed project. These meetings provide staff the opportunity to offer suggestions and comments related to the environmental, engineering, and safety features of the proposed project. Based on the input received, the project sponsor will be able to further define their proposed project. Once there is sufficient project definition, the sponsor may submit its request to initiate the pre-filing process to the FERC's Director of the Office of Energy Projects (Director).

Pre-Filing Review Process

If the Director approves the request, FERC will issue a notice informing the public of the initiation of the pre-filing process. As part of the pre-filing process, a potential applicant is required to implement a Project Participation Plan. The plan must identify specific tools and actions to facilitate stakeholder communication and the dissemination of public information to those who are interested in the proposed project.

During the pre-filing process, FERC staff will review the company's proposal and identify information needed for the preparation of a complete application. Staff activities may include: conducting site visits, facilitating the identification and resolution of issues, coordinating with other agencies, and initiating the environmental review of the proposed project. By engaging stakeholders early in the process and resolving relevant issues, the proposed project will become better defined and the benefits and impacts of the proposed project will be better understood. The work performed in the pre-filing process will form the basis for the application that is subsequently filed with FERC.

Application Process

An application may be filed only after the Director has determined that all necessary information gathering is complete. After an application is filed, FERC staff will conduct a comprehensive project review, including issuing an environmental document. All comments and recommendations from all affected entities and individuals will be compiled and carefully reviewed. FERC staff may conduct public meetings and technical conferences, as appropriate, to clarify project-related issues. After the issuance of a final environmental document, FERC will act on the request for a construction permit.

V. FINANCING NEW TRANSMISSION PROJECTS

Public Utility Transmission Owners and Rate Base Funding of Transmission Projects

Public utility transmission projects typically involve upgrades or additions to existing transmission infrastructure for the purpose of relieving congesting, managing load growth, and improving reliability (reducing power outages) and increasing resiliency (ability to recover from power outages). If small enough, these projects are financed by using internally generated funds. Larger projects use a combination of debt and equity. Debt, in this context means borrowing funds from commercial lending institutions through lending agreements or the utility issuing corporate bonds. Equity, in this context, means issuing corporate stock, which is purchased by insurance companies, pension funds, and other entities with large cash holdings.

The capital raised in this manner is used to finance construction of the transmission facilities, which become assets (priced at their capitalized costs) that are added into the utility's total rate base (the value of the assets used in providing the utility's services). Regulators allow the public utility to charge rates high enough to recover its actual debt costs, its cost of equity, and a rate of return on the equity portion of its rate base. (Independent transmission companies fall into the same **rate base model** of obtaining investment capital.)

The rate of return on equity, plus return on investments, becomes the utility's earnings (profits). Investors' risk of repayment is minimized through regulatory approval of transmission and other charges that are designed to permit the utility to recover sufficient revenue to pay its operating expenses, capital costs (debt and equity) and other costs incurred in order to provide transmission and other services. Where the public utility has, along with other public utilities, surrendered operational control of its transmission lines to an RTO or ISO, the grid access charges of the RTO or ISO recover the revenue necessary to repay the capital and other costs of these public utility transmission owners.

Restrictions on the amount of financing that can be raised in the manner for new transmission projects are based on the public utility's balance sheet. If the utility's level of debt is high in relation to the value of its assets, it is said to be highly leveraged and is a less attractive target for lending, as the perceived risk of loan default is higher. To attract capital in face of this perceived risk, the utility has to agree to pay higher interest rates (an increased cost of debt). A utility may seek to increase the share of equity funds in its capital structure so as to avoid excessive leverage. Regulators, however, recognize that equity is more expensive than debt and to protect ratepayers, are reluctant to approve rates that represent more than a 50% equity component in the utility's capital structure (combined total of debt and equity).

Securitized financing allows a public utility to raise capital and keep the costs off of its balance sheet. Securitized financing is an arrangement in which the right of a public utility to collect certain charges from its customers through a regulatory surcharge to rates is recognized by law as a property right. The utility irrevocably sells this property right to a special purpose affiliate. The special purpose affiliate then issues bonds in the amount needed for financing the energy project. The bonds are secured by this property right. Bond proceeds are given by the special purpose entity to the utility as payment for the property right. The customer surcharge payments are collected monthly by the utility, as agent for the special purpose entity and then delivered to that entity. The special purpose entity uses these amounts to pay the debt service on the bonds and to pay for retirement of the bonds.

To make this property right irrevocable, the government passes legislation that irrevocably guarantees that the public utility's customers will be charged sufficient amounts each year (through a surcharge to existing rates) to provide for the required payments to bond holders. The regulatory agency overseeing the public utility's rates issues a financing order that provides for the computation of an initial surcharge level, provides for the annual true-up of the surcharge level each year to avoid over or under-collection of the amount needed by bondholders, and otherwise provides for the certainty of this funding mechanism. The advantages of securitized funding is that it lowers the overall lifetime costs of the energy project. This is because the interest rate on the bonds is below what is charged for non-securitized transactions, the bond repayment period is usually one-half the period for debt retirement in rate base financing, and (since the financing obligation does not rest on the public utility) the public utility is not allowed to earn a rate of return on the capital costs of the energy project.

<u>Merchant Transmission Projects</u>

Because of the immense costs involved, some large scale, off-grid transmission projects, such as those used to transmit energy from renewable generation projects (for example, wind farms and concentrated solar arrays) are not able to be financed by public utilities using rate base funding. With lack of public utility participation, new merchant transmission companies have come into existence to develop these projects. These are usually special purpose entities, sometimes created as joint enterprises of multiple investors, that are formed specifically to finance, construct, and operate transmission lines. Unlike public utility transmission owners, they have no captive customers, and they assume all financial risk associated with building a transmission project.

These projects use a method of raising capital that is called **project financing**. In project financing, the assets of the developer are not available to lenders in the event of a loan default. Instead of company assets being used as collateral or security for the debt assumed by the company, the future revenue stream from the project becomes assurance for loan repayment. There are various degrees of certainty that may attach to this future income stream, with more certainty meaning less risk, which lowers the cost of capital to the project's investors. Unlike the case with securitized financing, the transmission rates are not protected against future regulatory changes that may place project cost recovery at risk. It is common for project financed transmission facilities to be developed and owned by multiple investors using a structure called a master limited partnership, rather than a corporation. With corporate ownership, project revenue is taxed once to the corporation, in the form of a corporate income tax, and then taxed a second time after the revenue is distributed to shareholders as dividends. In a partnership structure, the project's revenue is not taxed to the partnership, but is only taxed to the partners, once received by them as a distribution of partnership earnings. As a result, net earnings are increased through use of the master limited partnership structure.

FERC open access rules initially proved to be an obstacle for project financing new merchant transmission projects. Open access, FERC ruled, required that capacity be given on a first come/first-served basis. An open season would be held for a period of time (usually 30 days) in which capacity would be offered. Subscribers to the capacity during the open season would form a queue, in which the first to subscribe obtain the highest position on the queue. Queue position determined whether or how much capacity would be allowed to that subscriber, and to a certain extent, at what cost. Parties were reluctant to be initial subscribers because those bore the highest share of the project costs; subscribers appearing later in time only paid the incremental cost of infrastructure expansion or upgrade, and thus had lower rates. This provided these late comers with a competitive advantage when marketing energy.

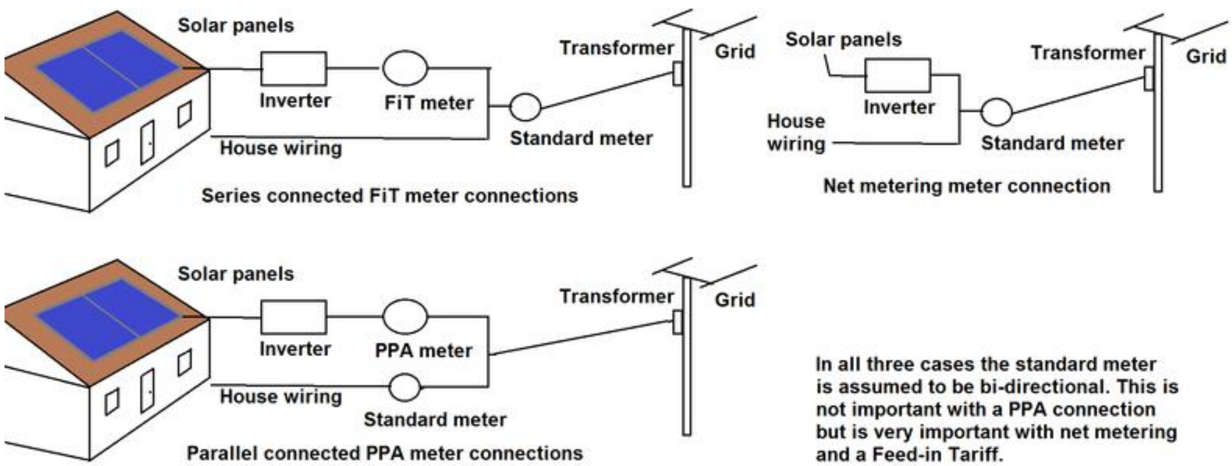
Consequently, FERC evolved a number of changes to encourage these projects to go forward. The first-come/first-served definition of non-discriminatory access was relaxed so that clusters of subscribers could be bundled together and pay the same rate. FERC also allowed merchant transmission companies to pre-sale up to 75% of the capacity of a transmission project to "anchor" customers, before offering the remaining capacity in an open season. The merchant transmission companies were allowed to charge lower rates to these anchor customers, when compared against the rates to be charged to those subscribing to capacity in an open season.

Capacity commitments may be made by subscribers through conditional precedent agreements. Precedent agreements could be written with a timeline of various development milestones. Failure to meet these milestone dates would allow the subscriber to opt out of the agreement. Other opt out conditions could be written into a precedent agreement. For this reason, precedent agreements lack the same level of certainty as provided by a transportation agreement. In contrast, a firm transportation agreement which binds each part to performance, unless released by mutual consent, offers greater certainty that transportation service will occur, revenue raised, and loans repaid.

Other ways of increasing certainty involve obtaining loan guarantees from the U.S. Department of Energy. These loan guarantees obligate the U.S. government to repay investor contributions to capital, in the event the project does not go forward or, for some other reason, the merchant transmission company does not repay its loan obligation. Public/private partnerships, in which a government agency will be a co-sponsor of the project and bring public funding into the financing of the project, also minimizes investor risk.

VI. BEHIND-THE-METER GENERATION

The movement to replace hydro-carbon fueled generation and nuclear power with renewable generation resources, particularly solar and wind resources, received a stimulus in the U.S. when, in the 1980s, individual states began requiring electric distribution utilities to let energy enter their distribution grid from solar, and then wind, generators located on the premises of existing electric utility customers. Referred to as "behind-the-meter generation" these resources (which may now include home fuel cells and vehicle-to-grid ("V2G") plug-in rechargeable electric vehicles) offered benefits to the utility in the form of demand-side management (peak load shaving), to the individual customer in reducing its electric utility costs, and to the environment as part of state clean climate initiatives.



Understanding Feed-in Tariff and Power Purchase Agreement meter connections

There are three basic ways in which utilities may account for this behind-the-meter generation. The most prevalent method in the U.S. is called "**net metering**." With net metering, the utility utilizes a bi-directional meter to record the end-user's receipt of energy delivered through the utility's distribution grid and also records the energy flowing from the end-user back into the utility's grid. These two amounts are netted against each other to produce either a net consumption, billed to the customer, or a net surplus. When there is a net energy surplus, the surplus is carried over to the next month as a credit against the future month's energy deliveries.

Net metering is a way of accounting for physical transfers of energy, with indirect financial benefits to the utility, in terms of lowering its generation costs through reduced demand at peak periods throughout the day, and to the customer, in terms of reducing the amount of energy consumption billed to it by the utility. A 2005 U.S. law now requires all public utilities in the U.S. to offer net metering, upon customer request. In Washington D.C, net metering is calculated as the physical difference (kilowatt-hours) between consumption and generation, but is billed or credited to the customer at the utility's full retail distribution energy rate, applied against the net kilowatt hours. In Washington, D.C., the offset through net metering is recorded as a financial, rather than physical, offset.

About 60% (3,500 MW) of the cumulative U.S. market for solar generation now comes from behind-the-meter net metering. Of this amount 2,800 MW is concentrated in five states: California, Hawaii, Arizona, New Jersey and Colorado.

Another form in which utilities respond to behind-the-meter generation is by negotiating a **Power Purchase Agreement** “PPA”) with the end-user. Under this arrangement, two uni-directional meters are installed—one records electricity drawn from the grid, and the other records excess electricity generated and fed back into the grid. The end user pays the retail rate for the electricity they use, and the utility or power provider purchases the home owner’s generation at the utility’s avoided cost of power. When the energy commodity costs are compared, the difference in commodity costs helps determine the extent of the benefits received by both parties.

There are several pricing variations used when accounting for the utility’s receiving behind-the-meter generation. In **market rate net metering** systems the user's energy use is priced dynamically according to some function of wholesale electric prices. Net metering applies such variable pricing to excess power produced by a qualifying systems.

Market rate metering systems were implemented in California starting in 2006, and under the terms of California's net metering rules are applicable to qualifying photovoltaic and wind systems. Under California law the payback for surplus electricity sent to the grid must be equal to the variable price charged at that time. Market rate pricing is very similar to **time of use** pricing for use with net metering.

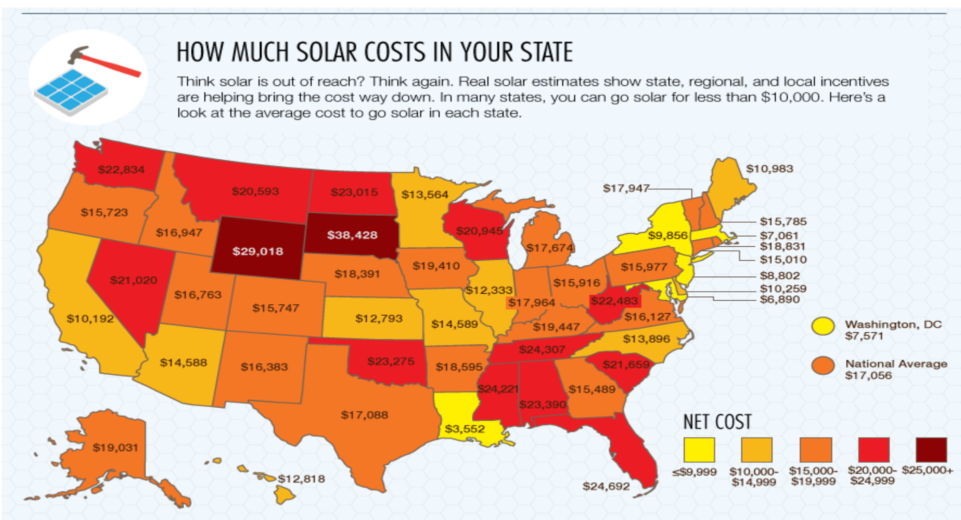
Time of use net metering employs a specialized reversible remotely read “smart” electric meter that is programmed to record electricity usage at all times during the day. Time-of-use allows utility rates and charges to be billed based on the different demand-based rates being charged by the utility at different times of the day or night, or even seasonally. Typically the production cost of electricity is highest during the daytime peak usage period, and low during the night, when usage is low.

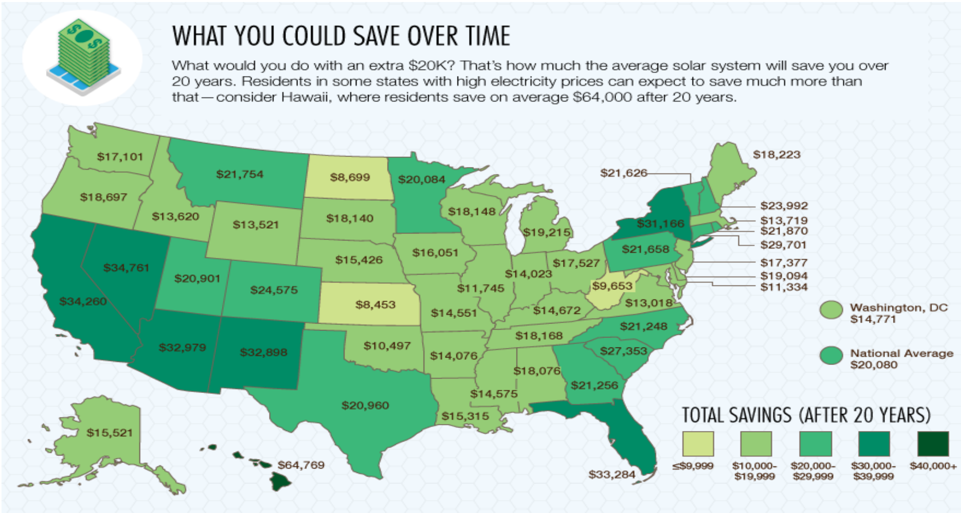
Time of use metering is a significant issue for home-installed renewable energy resources, since, for example, solar power systems tend to produce energy during the daytime peak-price period, and produce little or no power during the night period, when price is low. If an end-user shifts its peak load to the utilities off-peak hours, the net energy imbalance is priced higher and the price differential increases the financial benefits reaped by the end user.

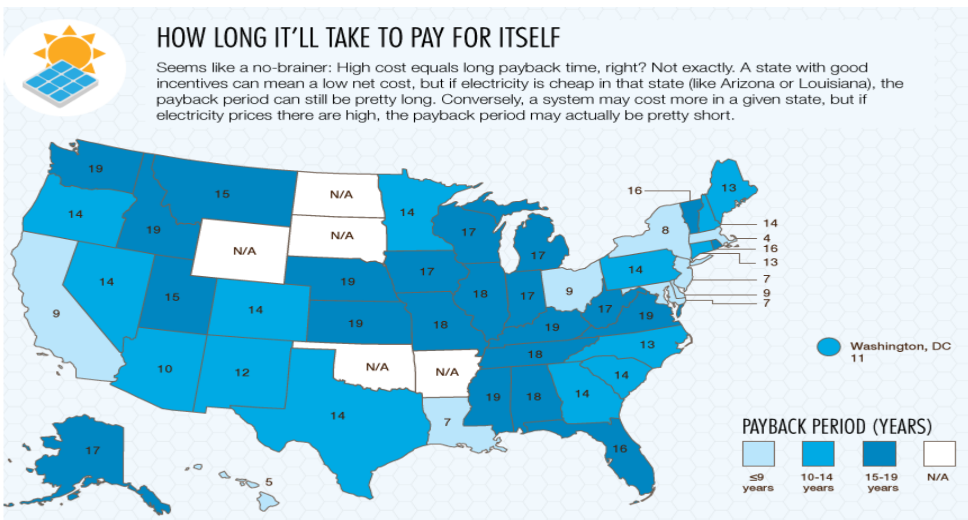
The third manner in which utilities acquire power from behind-the-meter generation is b negotiating an agreement with the end user under a **feed-in-tariff**. This method is less common in the U.S, when compared against its use in Germany, Spain, and the Province of Ontario, Canada. With a feed-in tariff, customers are paid by the utility for all the electricity they generate from the renewable resource that is on its premises. The actual electricity being generated is counted on a separate meter, not just the surplus energy fed back to the distribution grid. The feed-in-tariff is one more means by which government offers incentives for home-based installation of renewable generation resources and promotes its clean climate initiatives.

In some U.S. states, utilities are permitted to charge a small connection fee in association with behind-the-meter generation. Sources that produce direct current, such as solar panels must be coupled with an electrical inverter to convert the output to alternating current, for use with conventional appliances. The phase of the outgoing power must be synchronized with the grid. For safety reasons, a mechanism must be included in the installation of the generator to disconnect the feed in the event of grid failure. Workers repairing downed power lines must be protected from "downstream" sources, in addition to being disconnected from the main "upstream" distribution grid.

In the U.S., home solar installations are heavily subsidized by tax credits, grants and utility rebates that help co-pay for the installation. Low cost loans are available from multiple federal, state and other sources to finance the purchase and installation of rooftop photovoltaic power generation systems. The U.S. Department of Energy's National Renewable Energy Laboratory estimates that with these credits, grants and rebates, the period of time needed for energy saving to equal the end users purchase and installation costs (payback period) ranges between one and four years, depending upon the technology behind the particular photovoltaic cell chosen. Estimated payback periods calculated in 2012 by a non-government source estimated payback periods between a low of four years (in Massachusetts) and a high of 19.7 years (in Arkansas).







VII. CONNECTION CHARGES IMPOSED ON RETAIL END USERS OF ELECTRICTY BY LOCAL DISTRIBUTION COMPANIES

Local electric distribution companies may require a new customer to pay a connection charge and, in some instances, a security deposit, when first receiving electrical service. However, not all states allow a utility to bill a connection charge for new residential customers. (New residential customers in Washington, D.C. are not required to pay a connection charge.) For residential customers, a connection charge is an administrative fee and does not pay the cost of the electric meter installed at the customer's location. Meter costs are recovered through the utility's distribution charges. The connection charge paid by commercial and industrial customers includes customer payment of all of the utility's interconnection expenses, including labor. The connection charge is a one-time fee that, for residential customers, is billed in most instances on the customer's first invoice. For commercial and industrial customers, connection charges are billed and must be paid prior to the commencement of electric service.

When a customer is a first-time recipient of a utility's service the customer may be required to pay a security deposit. This can be as little as $5.00 and is capped at no more than the equivalent of one or two months of estimated charges. A security deposit may be waived for those who are 60 years or older and will not be imposed when a customer can show that he or she meets the utility's credit standards. The purpose of this deposit is to provide funds the utility can draw against to pay an outstanding balance, in the event the customer's service has been terminated for non-payment.

Some states require that these deposits be held in segregated, interest-bearing accounts and not be co-commingled within the utility's general funds. Other states require segregated accounting and computation of interest, but allow the utility to use the funds as part of its working capital, subject to internal repayment. After the end of a defined period (usually one year), or after service is voluntarily closed, whichever is earlier, the utility will be required to return the deposit, plus interest, to the customer unless an outstanding unpaid balance remains.

In some states the utility is permitted to require a customer to pay a security deposit only in the event the utility decides the customer is not creditworthy. In those cases, a one-year satisfactory payment history usually is enough for the utility to decide the customer is creditworthy and to return the deposit, plus interest.

In **Washington, D.C.**, the Public Service Commission does not allow the electric utility to charge new customers a security deposit as a routine matter. Instead, a security deposit may only be required when the customer has exhibited conduct that makes the customer a payment risk. These behaviors are:

- The customer has been disconnected for nonpayment within the previous twelve (12) months;

- The customer has tampered with the service of the utility at the customer's previous premises within the twelve (12) months immediately preceding the customer's request for new service;

- The customer's account has an unpaid balance that has been delinquent in excess of sixty (60) days, at some point within the previous twelve (12) months; or

- The customer has an unpaid balance due to the utility for utility services at another address.

For **existing customers**, the D.C. Public Service Commission will allow a utility to require a deposit in cases where the customer has tampered with the service of the utility at the customer's premises within the twelve (12) months or the customer's Account has been delinquent in excess of sixty (60) Days within the previous twelve (12) months.

In many U.S. states, regulations require that when new distribution lateral lines are extended into new residential or commercial developments, these lateral lines and the individual customer service lines powered from the lateral lines, be placed underground. The incremental cost of undergrounding these lines is chargeable to the developer.

In Washington, D.C., the local electric utility is required to install underground lines for all new **residential** units and the undergrounding fee is $.50 per foot. When the developer pays this charge, it is considered a grant-in-aid-of-construction and treated by taxing authorities as income to the utility. For this reason, once the undergrounding fee is determined, the developer adds to this total an amount that is equivalent to the income tax the utility will be required to pay on the undergrounding fees received from the developer (between 30%-40%).

Commercial and industrial customers typically require more extensive interconnection facilities than what is used for residential customers. These facilities include utility poles, manhole frames, manhole covers or grates, and similar equipment. These customers are required to pay the utility for its actual costs for the equipment required to establish the interconnection, excluding the cost of metering.

Funds received by the utility as grants-in-aid-of-construction are separately tracked and accounted for in the utility's accounting system. These amounts are used as an offset to lower the value of the utility's total capitalized investment in its electric plant. Customer security deposits may be treated as if they are loans to the company and in that instance are used to reduce the utility's operating expenses, by reducing its working capital needs.

In summary, connection charges and security deposits must not be so high as to make it financially impractical for potential customers to acquire electric utility services. At the same time, connection charges must give the utility an opportunity to recover its interconnection costs, including equipment costs that are incremental to equipment costs being recovered through its system-wide distribution charges. Security deposits must be sufficient in amount to keep the utility's financial risks within investor expectations. Otherwise, the utility's cost of borrowing money may increase.

In Washington, D.C., these are particularly important considerations. As the nation's capital, it hosts a government that experiences large personnel changes every four to eight years. Therefore, the city experiences a quick cycle of arriving and departing residents. The area's electric utility estimates that up to 1/3 of its residential customer accounts change identity each year. Therefore, the D.C. Public Service Commission has rules in place that address the local utility's imposition of connection charges and security deposits in a manner that facilitates the transfer of electric service accounts and the creation of new accounts.