The Brattle Group

Transmission Investments and Cost Allocation: What are the Options?

Johannes Pfeifenberger

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Contents

Transmission Investments Increased Significantly

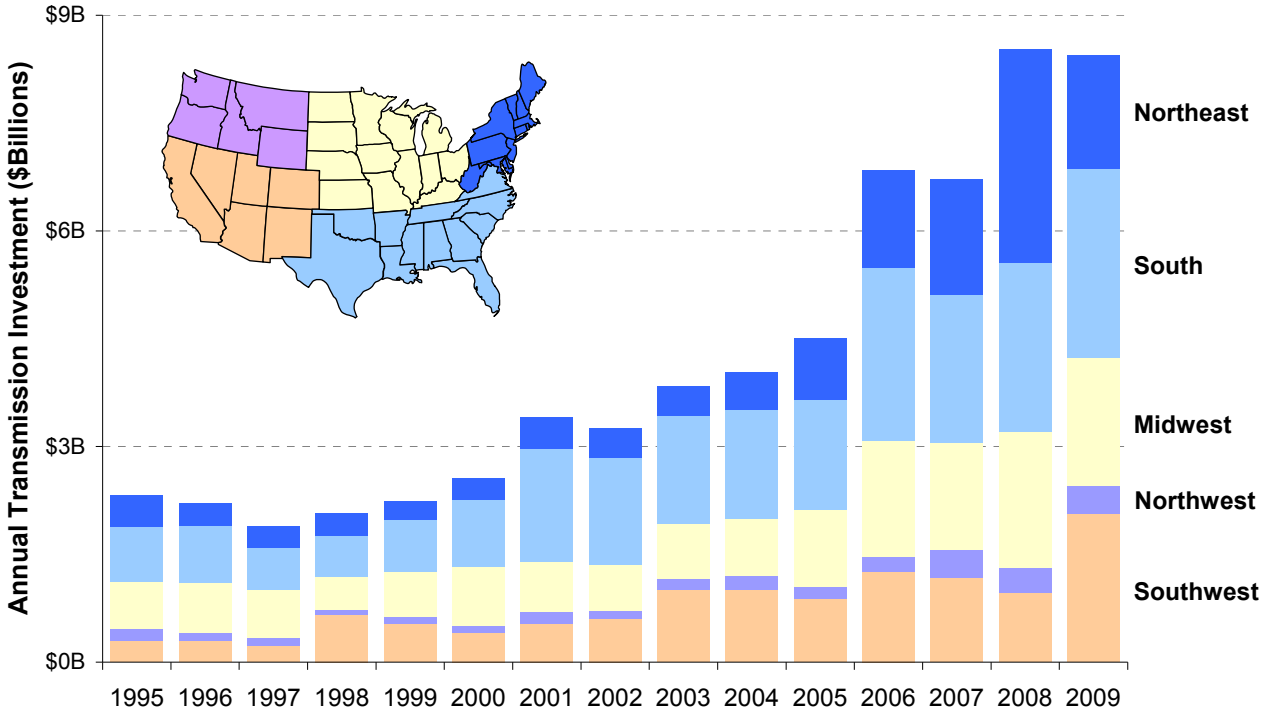
Significant increase in transmission for utility-specific and regional reliability projects:

- $2b/year in 1990s
- $8b/year in 2008-09

NERC predicts investment (in mostly reliablity and generation interconnection projects) to **triple** from about 1,000 miles/yr in 2000-08 to 3,000 miles/yr for 2009-2017

Additional regional upgrades now driven by state renewables requirements

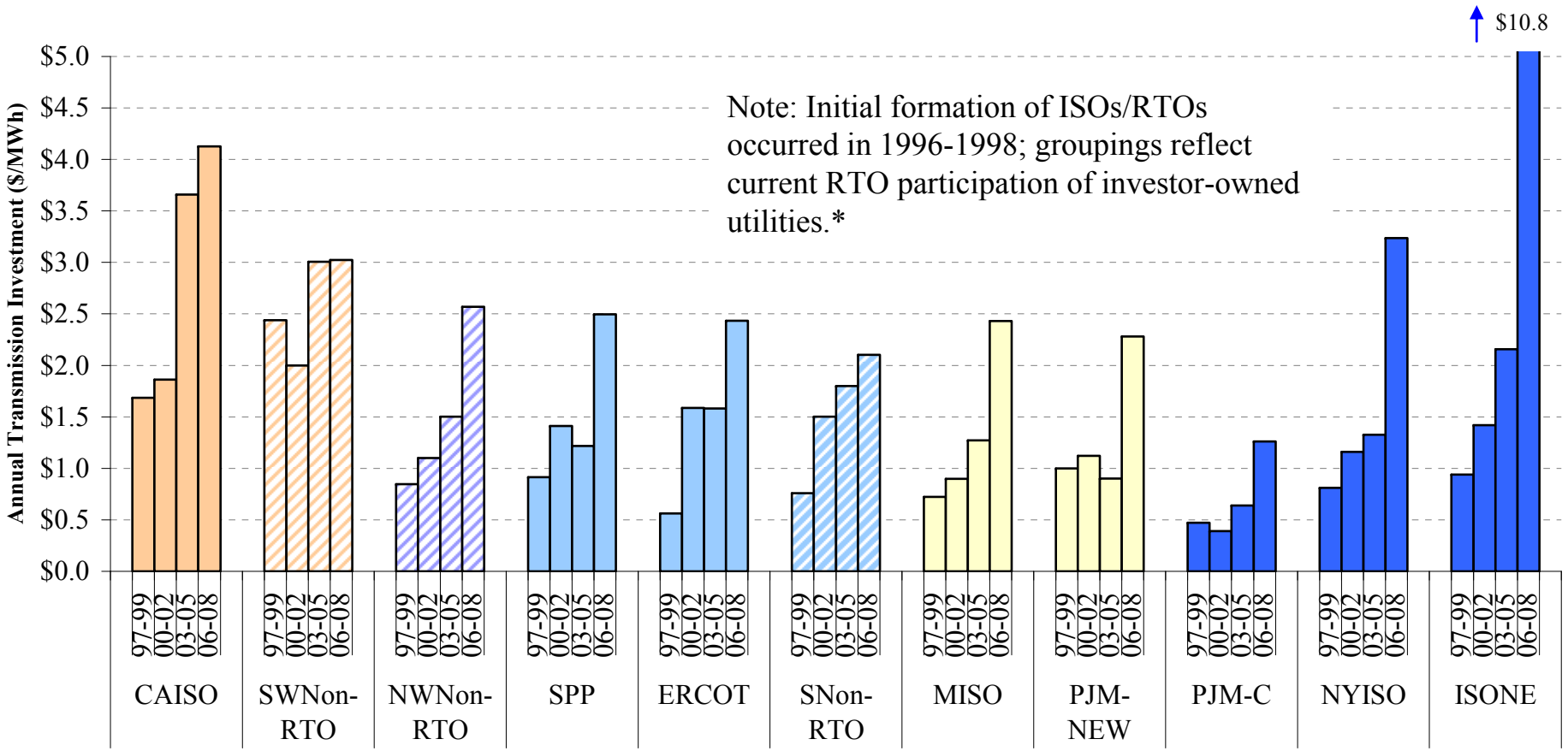
Annual Transmission Investment of Investor-Owned Utilities by FERC Subregion



Source: *The Brattle Group* based on FERC Form 1 data compiled by Global Energy Decisions, Inc., The Velocity Suite.

Transmission Investments Vary Across Regions

Transmission Plant Additions Per MWh of Regional Load by Investor-Owned Utilities



Source: The Brattle Group based on FERC Form 1 and EIA Form 861 data compiled by Global Energy Decisions, Inc., The Velocity Suite.
*Transmission investment of investor-owned utilities; expressed as total investment dollars per MWh of retail sales.
PJM-New includes Commonwealth Edison, AEP, Dayton, Duquesne, and Dominion. PJM-Classic includes all other PJM members.

A. Transmission Investments to Date

B. Looking Forward: Transmission Investment Needs

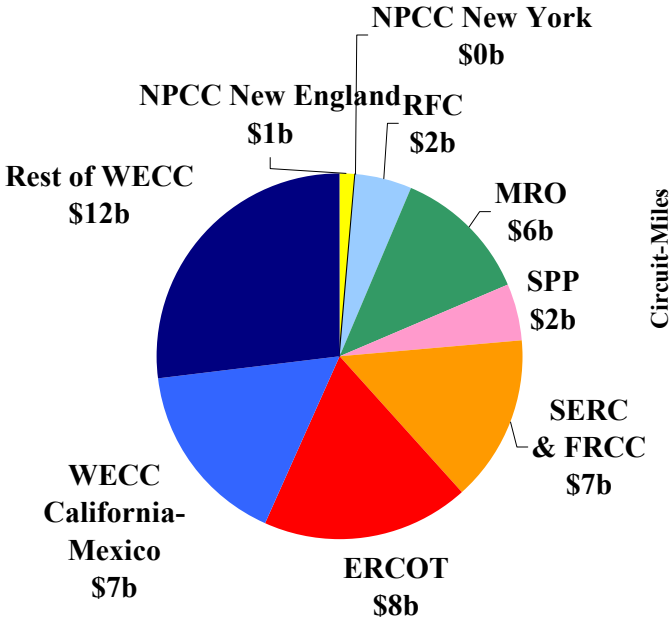
C. Transmission Cost Allocation: Options

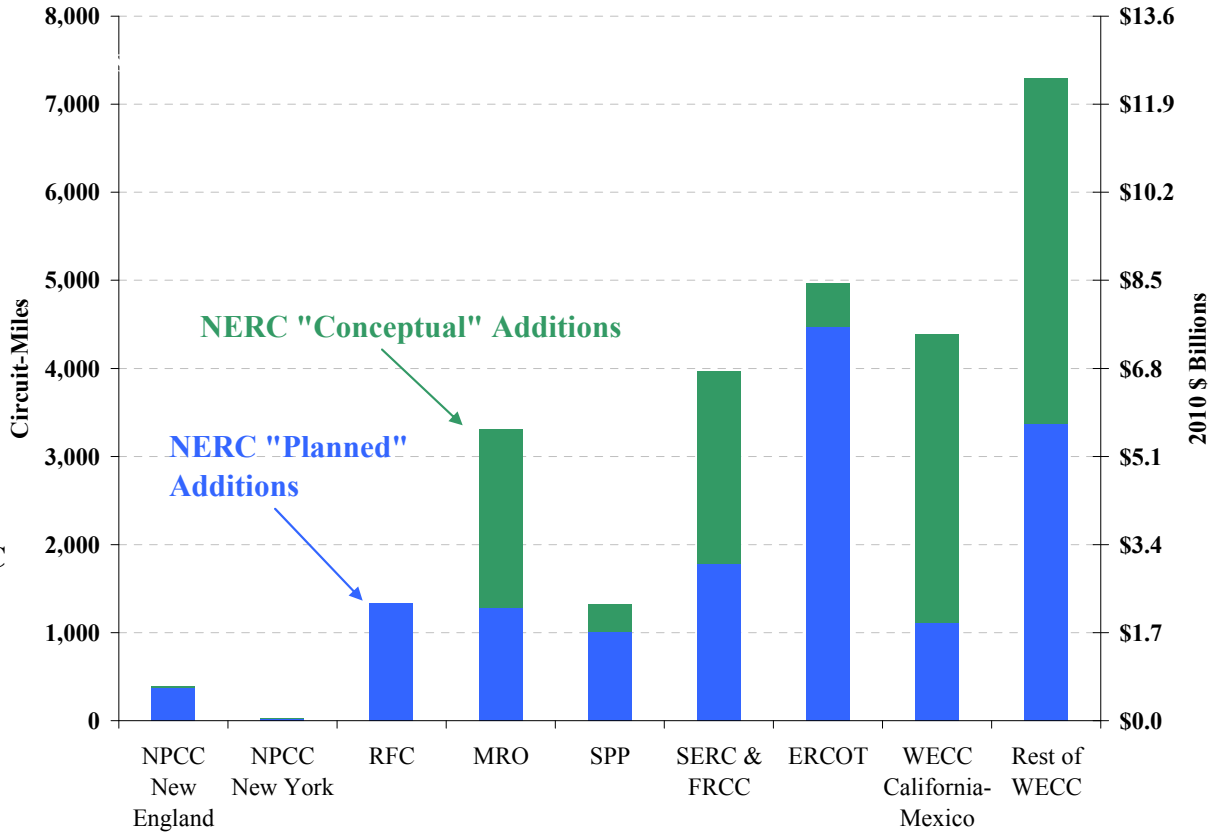
D. Recent FERC Actions on Cost Allocations

Additional Reading / About The Brattle Group

Looking Forward: NERC-Identified New Transmission

- NERC-identified transmission additions 2009-2018: 27,000 miles
- Estimated total investment cost approx. $50 billion





Notes: Estimated cost of transmission buildout based on NERC circuit-mile projections (2009-2018)
Average transmission buildout based on single circuit 345kV ($1.5 million/mile and $20 million/substation every 100 miles)

RPS Requirements: The New Transmission Driver

29 states and D.C. have an RPS; 7 States and 3 Power Authorities have Goals

WA: 15% by 2020

OR: 25% by 2025
5 -10% – smaller utilities

CA: 33% by 2020

MT: 15% by 2015

NV: 25% by 2025

UT: 20% by 2025

CO: 30% by 2020
10% – co-ops, munis

AZ: 15% by 2025

NM: 20% by 2020 – IOUs
10% – co-ops

TX: 5,880 MW by 2015;
500 MW non-wind goal

HI: 40% by 2030

ND: 10% by 2010

SD: 10% by 2015

NE Public Power Districts:
10% by 2020

KS: 20% by 2020

OK: 15% by 2015

MN: 25% by 2025;
30% by 2020 – Xcel

IA: 105 MW;
1 GW wind goal by 2010

MO: 15% by 2021

LA: 350 MW by 2012-13

MI: 10% MWh and
1,100 MW by 2015

WI: 10% by 2015

IL: 25% by 2025;
wind 75% of RPS

OH: 12.5% by 2025

WV: 25% by 2025

ME: 30% by 2010; 10% new by 2017;
8 GW wind goal by 2030

NH: 23.8% by 2025

VT: 20% by 2017; all growth to
2012 from RE and EE

MA:15% new by 2020, then 1%
annually; 2 GW wind goal by 2020

RI: 16% by end 2019

CT: 27% by 2020

NY: 30% by 2015

NJ: 22.5% by 2020

PA: 18% by 2020

DE: 25% by 2025

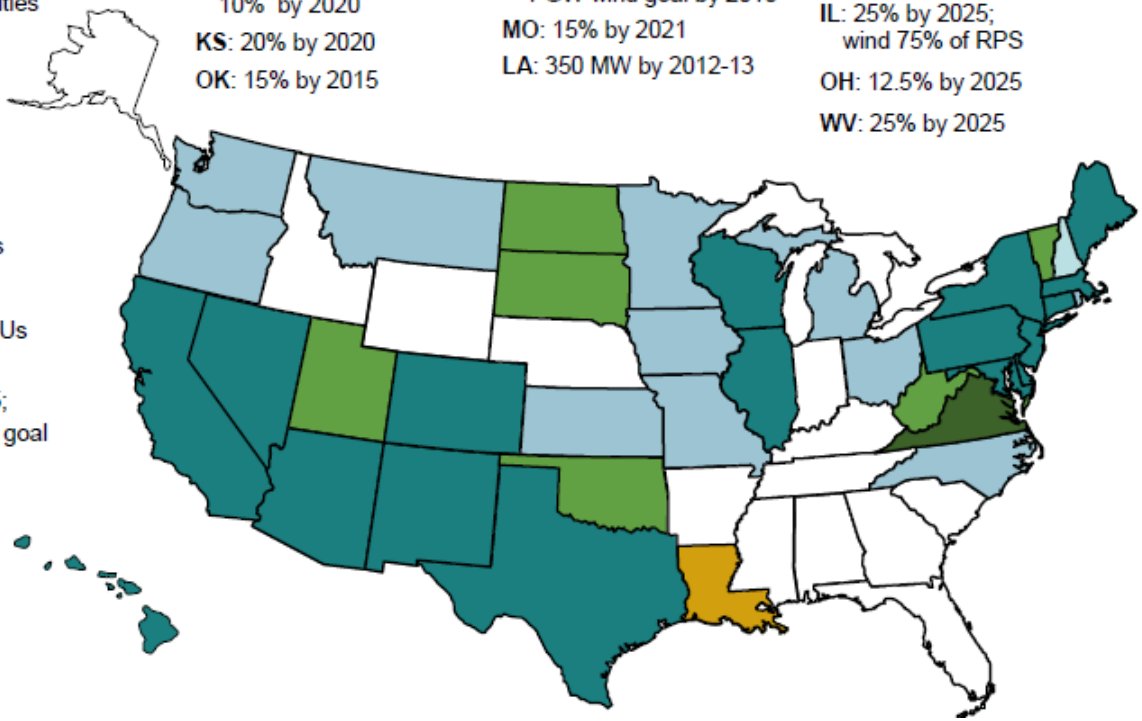
DC: 20% by 2020

MD: 20% by 2022

VA: 15% by 2025; goal with
production incentives

NC: 12.5% by 2021 – IOUs
10% by 2018 – co-ops, munis

TVA: 50% by 2020



- RPS
- Accelerated or strengthened RPS
- Voluntary State or Utility standards or goals
- Strengthened voluntary standard
- Pilot or study

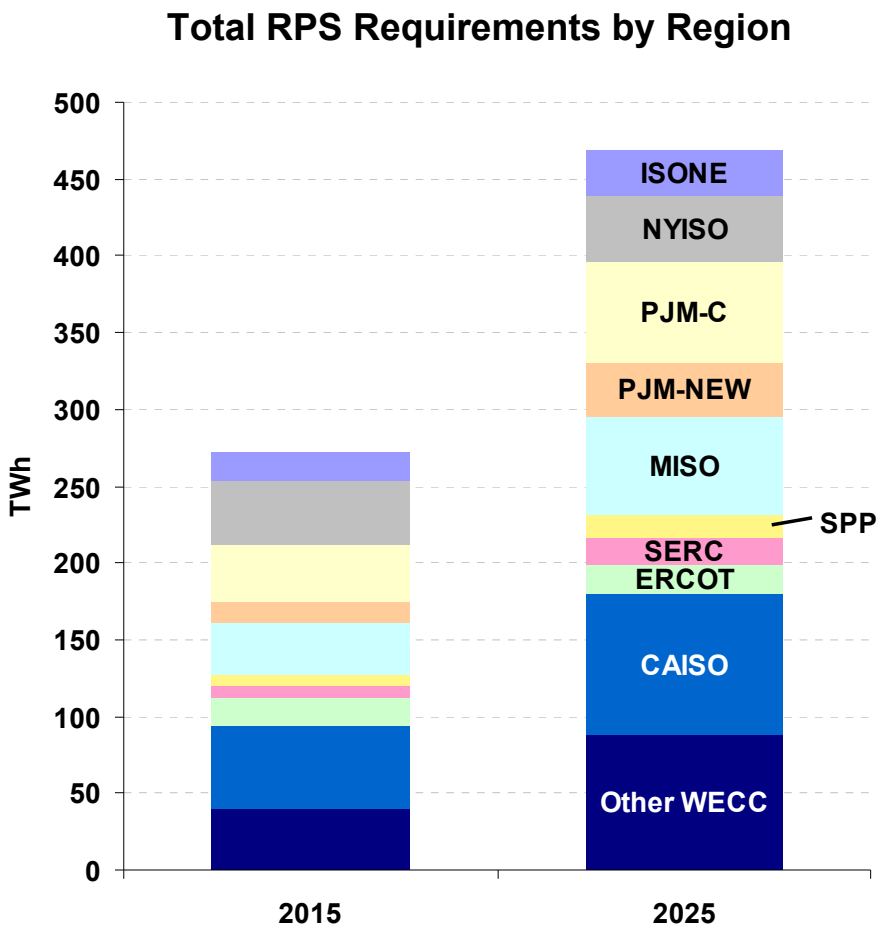
Note: nature of RPS requirements, baselines, and qualifying resources differ substantially across states (e.g., some may include nuclear and clean coal or large hydro, others give preference to in-state or off-shore resources, etc.)

Source: Federal Energy Regulatory Commission, "Renewable Power & Energy Efficiency Market: Renewable Portfolio Standards," as of August 11, 2010. Available at: www.ferc.gov/oversight

State Policy Drivers

State Renewable Portfolio Standards

- Current state RPS requirements are the only "on-the-books" driver for major new transmission investments other than reliability-driven upgrades.
  - Some states have very high RPS goals (e.g., 33% by 2020 in CA)
  - Compliance will require 270 TWh from renewable resources (55 GW, compared to 40 GW existing/under construction) by 2015 and 470 TWh (140 GW) by 2025; 20% federal RPS almost doubles that
  - The most cost effective renewable resources (wind and geothermal) are located far from load centers and the existing grid; other, more expensive renewables (solar, off-shore wind) also are "location constrained"
- Clear driver, but ultimate transmission build uncertain because states tend to modify their RPS requirements as high costs become more visible and policy requirements change (e.g., VT, IL, CT)



Source: *The Brattle Group* based on Energy Information Administration energy sales and RPS requirements as of August 2010. Does not include RPS goals.

Renewables-Driven Transmission Needs

Our analysis of transmission needs for renewables shows:

- Existing state RPS standards (if maintained unchanged) would drive approx. $55 billion (ranging from $40-70b) in transmission investments through 2025
- Adding a 20% federal RPS would increase transmission needs to approx. $100 billion ($75-130b range)
  - A 20% federal RPS would have largest impact on Southeast (few existing state requirements), followed by MISO, PJM, SPP, and non-CA portion of WECC
- Integrating already-proposed wind, solar, and geothermal plants would require approx. $85 billion ($60-110b) in transmission investments
  - Proposed capacity exceeds current RPS requirements, particularly in WECC
  - Thus, a significant portion of proposed plants likely not get built, reducing calculated transmission needs
- Comparison of RPS-driven and proposed-generation-driven transmission needs indicates likely future transactions between regions:
  - Exporters: SPP, MISO (without federal RPS), Other WECC, ERCOT
  - Importers: ISO-NE, PJM (particularly eastern), Southeast (only with RPS)

Brattle Database of Planned and Proposed Projects

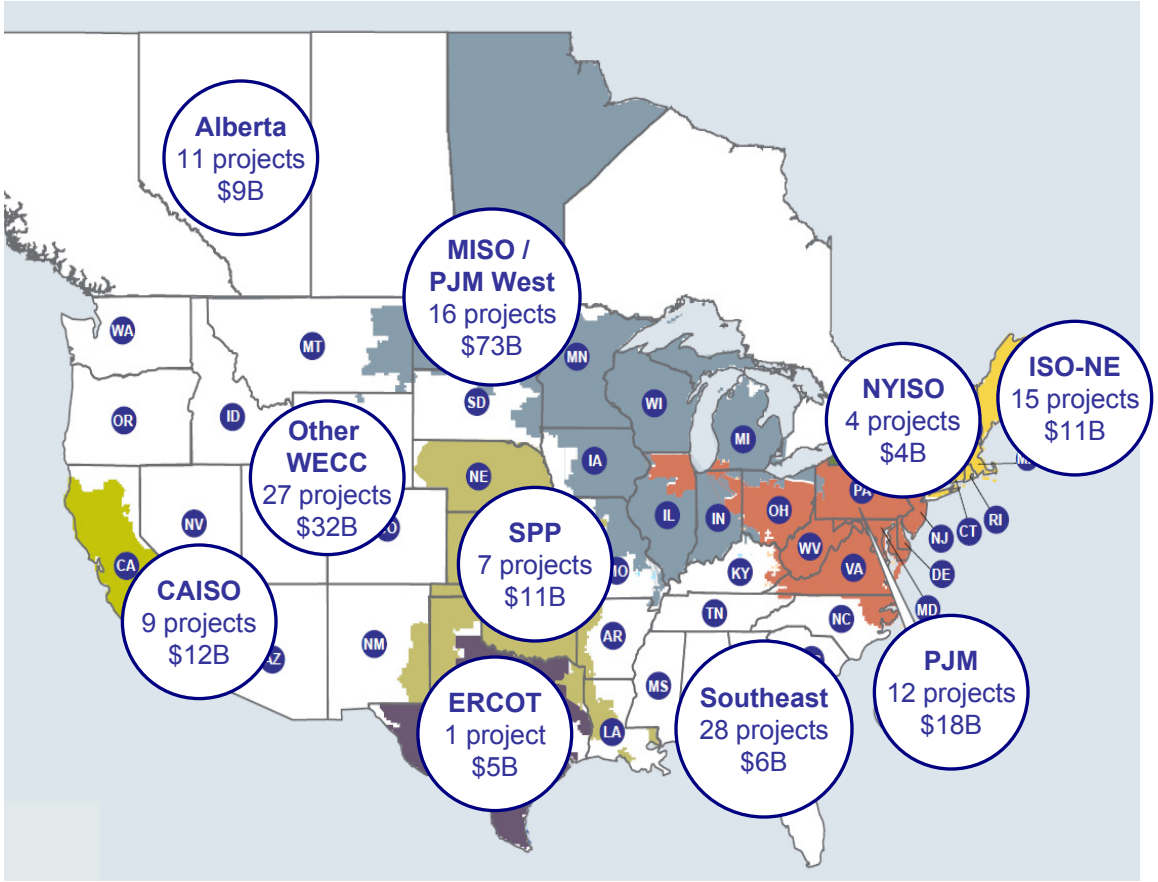
We identified approx.130 mostly conceptual and often overlapping projects (>$100 million each) for a total of over $180 billion

1/3 to 1/2 of these regional projects will not get realized due to:

- Overlaps with competing projects
- Planning and cost allocation challenge
- High costs

Large portion of these proposed projects are driven by large-scale renewables integration

$180 Billion of Planned and Conceptual Transmission Projects as of 9/10



Source: Map from FERC. Project data collected by *The Brattle Group* from multiple sources and aggregated to the regional level.

New Transmission Investment Needs: How Much?

NERC-identified planned/proposed projects through 2018:

$50 billion … estimated based on NERC circuit miles
(1/2 for reliability, 1/4 for renewables)

Of the $180 billion of individual projects identified earlier:

$30 billion … in RTO-approved plans
$80 billion … additionally proposed (non-overlapping)

$50-100 billion in US-wide incremental transmission needed to integrate renewables through 2025:

- To satisfy **existing state-level RPS** requirements

  $40-70 billion

- For **higher of existing state and 20% federal RPS**

  $80-130 billion

A. Recent Transmission Investment Trends

B. Looking Forward: Transmission Investment Needs

C. Transmission Cost Allocation: Options

D. Recent FERC Actions on Cost Allocations

Additional Reading / About *The Brattle Group*

Cost Allocation and Recovery Approaches

Five widely-used methodologies to allocate and recover costs from transmission customers

1) License plate (LP): each utility recovers the costs of its own transmission investments (usually located within its footprint).
2) Beneficiary pays: various formulas that allocate costs of transmission investments to individual Transmission Owners (TOs) that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their LP tariffs from own customers.
3) Postage stamp (PS): transmission costs are recovered uniformly from all loads in a defined market area (e.g., RTO-wide in ERCOT and CAISO).
   - In some cases (e.g., SPP, MISO, PJM) cost of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their LP tariffs.
4) Direct assignment: transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity.
5) Merchant cost recovery (M): the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.

Cost Allocation: What Works and What Doesn't

Existing cost allocation and recovery processes have varying degrees of effectiveness.

- Works well: cost recovery for traditional single-utility, single-state projects built to satisfy reliability needs
- Mostly works: cost allocation and recovery at the RTO level for reliability-driven regional projects and *conventional* generator interconnection requests
  - Some unintended consequences of existing RTO cost allocation framework
  - MISO's assignment of wind integration costs illustrates difficulties
- Still mostly **un**resolved: Cost allocation and recovery for all other types of regional projects, including "economic" projects, *renewable integration* projects, EHV overlay projects, and any multi-purpose projects
  - Two single-state ISOs (ERCOT and CAISO) were the first to resolve cost allocation for multi-utility, multi-purpose, and renewable integration projects. Now SPP has largely resolved this issue, too
  - Midwest ISO filed a new cost allocation methodology for regional multi-purpose projects at the FERC in July
  - Other RTOs and regions have only started to address this issue
  - Court remand of PJM postage stamp tariff creates additional uncertainty

FERC Transmission Policies

Summary of Current Cost Allocation Methodologies

LP = License Plate Tariffs; PS = Postage Stamp Tariffs or Postage Stamp Allocation; M = Merchant Lines; GI = Generation Interconnection Tariffs;
✓ = workable approach; n/a = workable approach not yet available

RTO/ Region	General Tariff Methodology	Reliability	"Economic" Projects	Renewables	Regional/Overlay Projects
CAISO	PS 100% ≥200kV; otherwise LP or M	✓	✓	✓ GI and location-constrained resource tariff (Tehachapi)	✓ Not specifically discussed, but 100% PS of all network facilities
ERCOT	PS or M	✓	✓	✓ CREZ (100% PS)	✓ Not specifically discussed, but 100% PS of all network facilities
SPP	PS 33% ≥60kV reliability projects; PS allocation for balanced portfolio; otherwise LP or M	✓	✓ "Balanced Portfolio" allocation	✓ GI; Highway/Byway PS treatment	✓ Highway/Byway PS treatment
Southeast	LP (utility specific tariffs)	✓	n/a	n/a (GI only)	n/a
ISO-NE	PS 100% ≥115kV; otherwise LP or M	✓	too narrowly defined	n/a (GI only)	n/a
PJM	PS sharing 100% ≥500kV; otherwise LP allocation (beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
MISO	PS sharing 20% ≥345kV; rest LP allocation (beneficiary pays) or M; pending MVP approach	✓	too narrowly defined	Multi Value Project ("MVP") PS treatment (filed July 2010)	MVP PS treatment (filed at FERC July 2010)
PJM-MISO	Sharing of reliability project based on net flows/beneficiaries	✓	too narrowly defined	n/a	n/a
NYISO	LP allocation (based on beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
WECC (non-CA)	LP; often with cost allocation based on co-ownership	✓	✓ (differs across WECC subregions)	✓ GI (*e.g.*, BPA open season); under discussion in WREZ	n/a – under discussion in WREZ

New Tariff-Based Cost Recovery Approaches

New OATT-based approaches:

- CAISO:
  - Postage stamp for all network upgrades ≥200kV
  - *Tehachapi LCRI* approach: up-front postage stamp funding of project, later charged back to interconnecting generators, thereby solving chicken-egg problem
- ERCOT:
  - Postage stamp for all *CREZ* transmission being built to integrate 18,000 MW of new wind; build-out awarded to a diverse set of 7 transmission companies
- SPP:
  - Developing $1.1 billion Priority Projects under FERC-approved postage stamp ("highway/byway") recovery
- MISO:
  - Filed at FERC the "Multi Value Project" postage stamp recovery in July 2010
  - FERC decision anticipated later this year
- WECC:
  - Co-ownership of lines (within and out of footprint) based on contractual allocations of point-to-point capability to resolve cost allocation issue
  - BPA open season approach for >5,500 MW renewable generator interconnections
  - Northern Tier's multi-state cost allocation committee

Non-Tariff-Based Cost Recovery Options

New cost recovery options that bypass the RTO's OATTs:

- Long-term merchant PPAs:
  - HVDC cable from PJM to LIPA financed with long-term PPA for capacity
  - Example: Neptune (independent transmission LLC)
- Merchant anchor tenant with open season:
  - Anchor tenant signs up for large portion of capacity, open season for rest
  - Standard model used for new pipelines
  - Example: Zephyr and Chinook HVDC lines (TransCanada)
- Regulated PPA with ISO operational control:
  - Utilities own transmission, sold bilaterally to generator at state regulated rates, buy bundled long-term PPA
  - Project under RTO operational control but bypasses RTO cost recovery
  - Example: NU-NSTAR-HQ HVDC link
- Participant funding with cost-based rates for transmission service:
  - Stand-alone transmission company to construct and own AC collector system and charge cost-based rates for long-term transmission, balancing, and firming service
- Mostly used for HVDC lines because (by being "controllable" like pipelines) they allow owners/customers to capture more of the benefits than from AC projects

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FERC's NOPR on Planning and Cost Allocation

FERC's NOPR has significant implications for economic analyses and cost allocation of new transmission projects. It addresses:

- Public policy consideration – transmission planning must consider public policy requirements established by state or federal laws or regulations
- Mandatory regional transmission plans – regions must develop and file actual transmission plans
- Inter-regional planning process – neighboring regions must coordinate and have a transmission planning process that considers reliability, economic, and public policy projects that span both regions
- Cost allocation – regional and inter-regional plans must include cost allocation for reliability, economic, and public policy-driven projects
- Right of First Refusal – Remove ROFR from tariffs; does not preempt state-specific rules; adds process for independent developers seeking tariff-based cost recovery and participation in regional plans

Details on Specific FERC NOPR Components

- Regional cost allocation principles
  - Allocation should be based on "cost causation" or "beneficiary" principles (should be "at least roughly commensurate with estimated benefits")
  - Costs can only be allocated to regions in which the facility is located
  - Those that receive no benefit must not be involuntarily allocated costs
  - Facilities located entirely within one transmission owner's service area do not require (but can be granted) regional allocation
  - Postage stamp may be appropriate:
    - If all customers tend to benefit from class or group of facilities
    - If distribution of benefits likely to vary over long life of facilities
  - FERC will use backstop cost-allocation authority if no agreement is reached amongst regional stakeholders
- Interregional Planning and Cost Allocation
  - Regions need to share plans and coordinate planning processes
  - Requires cost allocation methodology for projects spanning both regions
  - Cost of facilities located solely in one region cannot be allocated to neighboring region (unless voluntarily/with agreement)

Cost Allocation Challenge: Benefits to Whom/When?

The benefits of regional transmission projects are:

▪ **Broad in scope**	▪ Renewables integration and environmental benefits ▪ Economic development from G&T investments ▪ Increased reliability and operational flexibility ▪ Reduced congestion, dispatch costs, and losses ▪ Lower capacity needs and generation costs ▪ Increased competition and market liquidity ▪ Insurance and risk mitigation benefits ▪ Fuel diversification and fuel market benefits
▪ **Wide-spread geographically**	▪ Multiple transmissions service areas ▪ **Multiple states** or regions
▪ **Diverse in their effects on market participants**	▪ **Customers**, **generators**, **transmission owners** in regulated and/or deregulated markets ▪ Individual market participants may capture one set of benefits but not others
▪ **Occur and change over long periods of time**	▪ Several decades ▪ Changing with system conditions and future generation and transmission additions ▪ Individual market participants may capture different types of benefits at different times

FERC's Recent SPP Order on Cost Allocation

The recently FERC-approved SPP "Highway/Byway" cost allocation methodology provides helpful guidance

- SPP's methodology (postage stamp for facilities ≥300kV) was developed by Regional State Committee in context of evaluating an actual set of "Priority Projects"
- SPP approved projects considering many different benefits types of benefits
  - Adjusted production costs insufficient, but 1.78 benefit-cost ratio overall after considering other benefits (value of reduced losses, wind revenue impact, gas price impact, reliability value, economic development value)
- In a separate analyses, SPP supported postage stamp cost allocation
  - Engineering analysis to show that EHV facilities ≥300 kV are largely used for region-wide energy transfers and therefore should have region-wide cost allocation
  - No state-level benefit-cost tests were performed, but economic analyses show most benefits are wide-spread and each state benefits in one way or another
- SPP Priority Projects and "balanced portfolio" projects also show that benefits of a group of projects will tend to be more-evenly-distributed than the benefits offered by individual projects (similar experience in ISO-NE)

FERC's Recent SPP Order on Cost Allocation

FERC approved SPP's Highway/Byway (postage-stamp) cost allocation methodology noting that it is roughly commensurate with benefits

- Users change over time and availability of system for use itself is a benefit to users as a whole
- Production cost savings are not the only metric relevant in considering whether costs are roughly commensurate with benefits
- Sole reliance on quantitative analysis to support cost allocation not required because:
  - Quantitative analyses may not accurately reflect true beneficiaries
  - Often do not consider "qualitative (less tangible)" regional benefits inherently provided by the EHV transmission network
  - Do not consider how function and benefits of individual facilities changes over time with system conditions and future generation and transmission expansions
  - Often do not capture how different customers realize different types of benefits at different times

The "Business Case" for Transmission Projects

Effective planning for economic and public-policy projects requires developing a "compelling business case"

- A challenge in any industry, but more difficult here due to complexity of challenges and often inadequate economics and policy orientation
- Essentially an "integrated resource planning" effort to chose among alternative generation and transmission investment options
- Requires iterations of economic and engineering analyses
- Challenges not faced in reliability planning:
  - Projects are "optional" – often different projects (with different benefits and costs) can meet the same objective
  - Many projects are unique, serve different purposes, and offer very different types of benefits that require different analytical approaches
  - Tools that capture only a portion of economic benefits
  - Lack of established evaluation processes to estimate economic value of many types of transmission benefits

Necessary to gain the broad multi-state support needed to obtain approvals, permits, and cost recovery

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Additional Reading / About *The Brattle Group*

Additional Reading

"Comments of Johannes Pfeifenberger, Peter Fox-Penner and Delphine Hou," in response to FERC's Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation (Docket RM10-23-000).

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The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies around the world.

We combine in-depth industry experience, rigorous analyses, and principled techniques to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

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Johannes Pfeifenberger (hannes.pfeifenberger@brattle.com)
44 Brattle Street, Cambridge, MA 02138
617-864-7900 (www.brattle.com)