ALLOCATING COSTS ROUGHLY COMMENSURATE WITH MULTIPLE TRANSMISSION BENEFITS

William W. Hogan

Mossavar-Rahmani Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

International Experience in Transmission Planning and Delivery

Imperial College, London

January 11-12, 2013

Conference organizers requested consideration of experience with transmission planning and delivery under the Standard Model.

- To what extent does/can/should nodal pricing and FTRs guide longer term investment decisions?
- How are potentially valuable transmission investments that benefit more than one utility's area identified?
- To what extent have RTOs facilitated such valuable region-wide transmission investments? Has this improved the situation or is more reform needed (and if so what)?
- What are the primary obstacles in identifying, planning and delivering wide-area transmission solutions?
- How has transmission planning been impacted by increased wind and smart grid solutions?
- How do properly functioning markets plan? What forms of private co-ordination arise?

The discussion here emphasizes the interaction of market design and transmission expansion cost allocation principles. This organizing framework connects with most, but not all, of these questions.

Developing rules for efficient transmission infrastructure investment may be easier said than done.

Transmission expansion interacts with electricity market design. For example, policies for smart grids emphasize better deployment of information and incentives. A major challenge is to improve the information and rationalize the incentives deployed. According to the White House plan:

> "A smarter, modernized, and expanded grid will be pivotal to the United States' world leadership in a clean energy future. This policy framework focuses on the deployment of information and communications technologies in the electricity sector. As they are developed and deployed, these smart grid technologies and applications will bring new capabilities to utilities and their customers. In tandem with the development and deployment of high-capacity transmission lines, which is a topic beyond the scope of this report, smart grid technologies will play an important role in supporting the increased use of clean energy.
>
> …
>
> This framework is premised on four pillars:

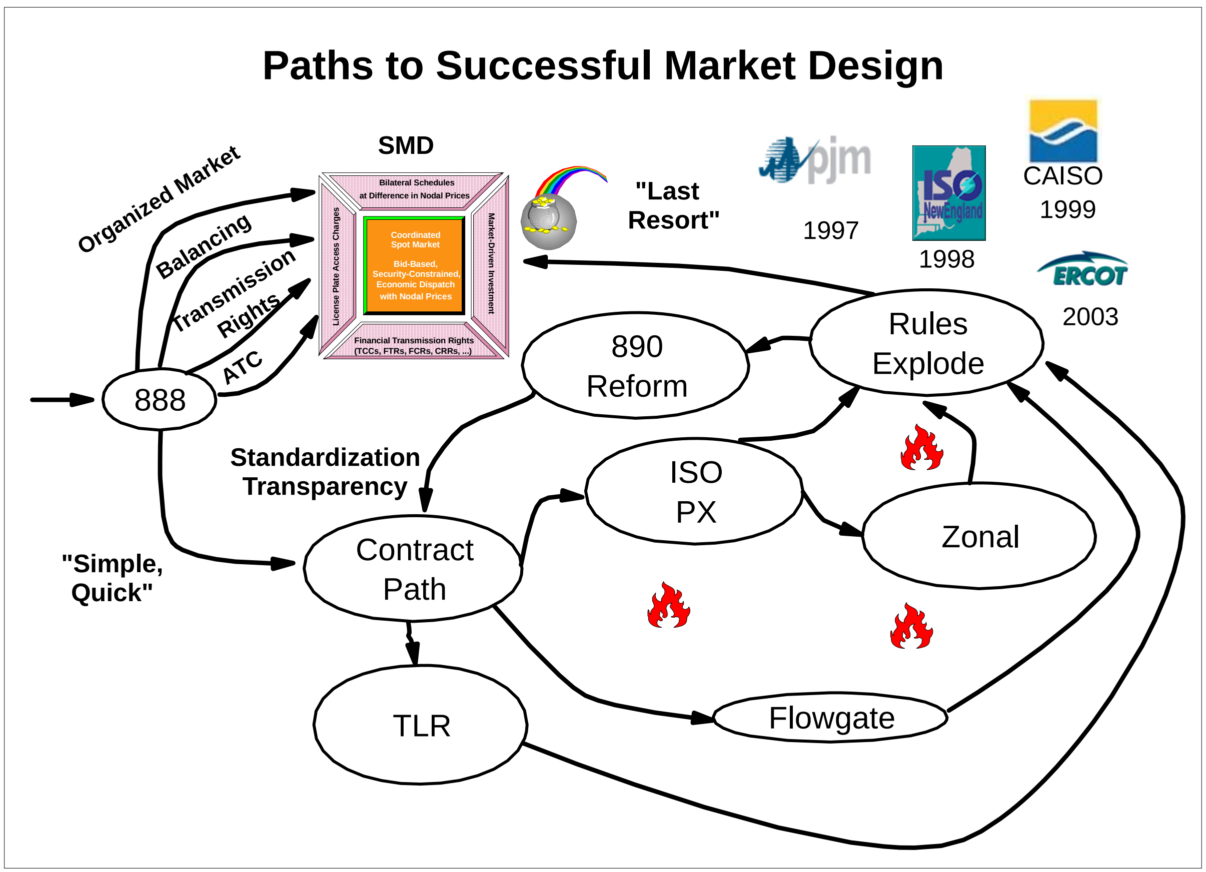
1. Enabling cost-effective smart grid investments
2. Unlocking the potential for innovation in the electric sector
3. Empowering consumers and enabling them to make informed decisions, and
4. Securing the grid." [1]

At least three of the four pillars imply a need for better cost allocation, pricing structures and market signals.

---

[1] Subcommittee on Smart Grid of the National Science and Technology Council, Committee on Technology, *A POLICY FRAMEWORK FOR THE 21st CENTURY GRID: Enabling Our Secure Energy Future*, White House, June 13, 2011, p. v.

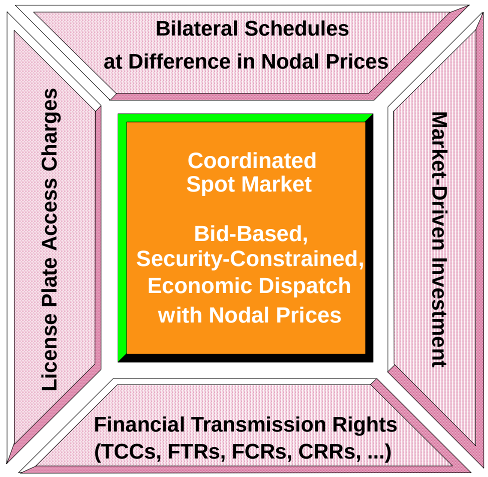
The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrated "path dependence," where the path chosen constrains the choices ahead. Early attempts with contract path, flowgate and zonal models led to design failures in PJM (`97), New England (`98), California (`99), and Texas (`03). Regional aggregation creates conflicts with system operations. Successful market design integrates the market with system operations.



The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000) Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, the Midwest, California, SPP, and Texas. This efficient market design is under (constant) attack.

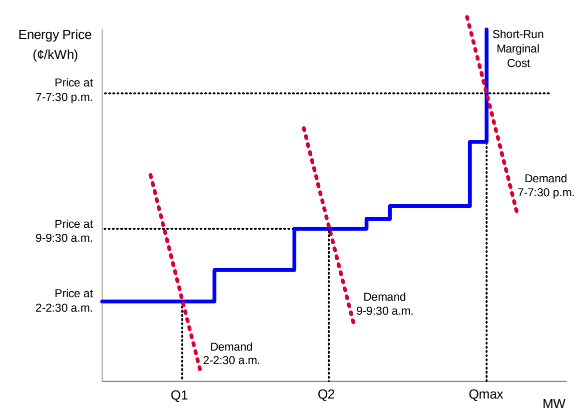
> "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."(International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 16.)

The ~~RTO NOPR~~ ~~Order~~ ~~SMD NOPR~~ "Successful Market Design" Contains a Consistent Framework

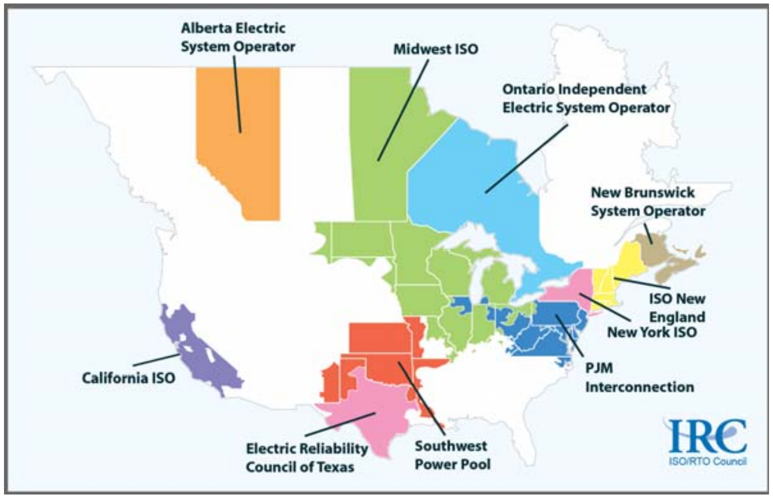


07/05
~~07/02~~
~~12/99~~
~~5/99~~

SHORT-RUN ELECTRICITY MARKET



Market design in RTOs/ISOs is well advanced but still incomplete.[2]



- **Regional Markets Not Fully Deployed**
- **Reforms of Reforms**

  California MRTU (April 1, 2009) and ERCOT Texas Nodal (December 1, 2010) reforms.

- **Market Defect: Scarcity Pricing, Extended LMP**

  Smarter pricing to support operations, infrastructure investment and resource adequacy.

- **Market Failure: Transmission Investment**

  - Regulatory mandates for lumpy transmission mixed with market-based investments.
  - Design principles for cost allocation to support a mixed market (i.e., beneficiary pays).

- **Market Challenge: Address Requirements for Climate Change Policy**

---

2 William W. Hogan, "Electricity Market Structure and Infrastructure," Conference on Acting in Time on Energy Policy, Harvard University, September 18-19, 2008. (available at www.whogan.com).

Transmission investment presents the most difficult challenges for an electricity market. In practice and in theory, market failures can be significant. If regulatory intervention is required to plan, coordinate and mandate transmission investment, how can the intervention reinforce the larger market design? A focus on market failures provides a framework that might work in theory. Comparison with the Argentine experience suggests the framework would work in practice. Getting this right is important, with implications for the ultimate success of electricity restructuring.

- **Level Playing Field.** A fundamental assumption of electricity restructuring is that market incentives and decentralized decisions would serve better than regulated decisions in determining investment and allocating risk.
    - Get the prices right.
    - Allow the market to determine the balance among investment alternatives.
    - Recognize that transmission is both a complement and a substitute for other investments.

- **Slippery Slopes.** Mandated investments not supported by market signals reveal or create requirements for expanding the scope of central planning and regulatory rather than market decisions.
    - All investments change the economics of all other investments.
    - Mandated investments tend to reinforce the distortions in price signals.
    - The regulatory cure could be worse than the market disease.

The policy framework includes elements to fit with the larger market design while allowing for transmission investments that are large and with increasing returns to scale and scope that may create material changes in market conditions. These "lumpy" investments create free-riding and transaction cost problems.

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing. The open access regime implies that spot prices may not support efficient transmission investment.

- **Focus on Transmission Expansion and Cost Allocation.** The dynamic framework envisions entry for new generation and load investments. Transmission expansions are sometimes competing and sometimes complements. Cost allocation is incremental and does not involve or require reallocation of network sunk costs.

- **Principled Treatment of Competing Generation and Load Investments.** Generation and load investments that face the same market failures as large scale transmission investments could be treated in the same way, but this would be a rare circumstance.

- **Regulated Transmission Cost Allocation Emulates Voluntary Contracts.** Absent free-riding externalities and coordination transaction costs, efficient transmission investments could be supported by voluntary contract. This would be compatible with the larger market design. This implies that "beneficiaries pay" is a necessary but not sufficient condition.

An outline of the earlier Argentine experience bears directly on the debate in the United States and elsewhere. (For details, see Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part I: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, pp. 27-28.)

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing.
- **Expansion of Transmission Capacity by Contract Between Parties**. Allowed merchant transmission with voluntary participant funding.
- **Minor Expansions of Transmission Capacity (<$2M)**. Included regulated investment with assignment of cost, either through negotiation or allocation to beneficiaries as determined by regulator, with mandatory participant funding.
- **Major Expansions of Transmission by "Public Contest" Method**. Overcame market failure without overturning markets.
  - Regulator applies the "Golden Rule" (the traditional Cost-Benefit Test).
  - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents.
  - Assignment of costs to beneficiaries with mandatory participant funding under "area of influence" methodology.
  - No award of Financial Transmission Rights!
  - Allocation of accumulated congestion rents to reduce cost of construction ("Salex" funds).

What impact did the Argentine approach have on transmission investment?

"To illustrate the change in emphasis on investment, over the period 1993 to 2003 the length of transmission lines increased by 20 per cent, main transformers by 21 per cent, compensators by 27 per cent and substations by 37 per cent, whereas series capacitors increased by 176 per cent. As a result, transmission capacity limits increased by 105 per cent, more than sufficient to meet the increase in system demand of over 50 per cent." (Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part II: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, p. 56.)

Lessons

- **Transmission investment could be compatible with SMD incentives.**
- **Beneficiaries could be defined.**
- **Participant funding could support a market.**
- **Award of FTRs or ARRs would be an obvious enhancement.**

RTOs in the US are struggling with the development of an adequate infrastructure investment policy. A major innovation appears in the New York ISO tariff that embraces the principles of the Argentine model.

> "The proposed cost allocation mechanism is based on a "beneficiaries pay" approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote."[3]

- **Beneficiaries pay.**
- **Participant funded expansions included.**
- **Regulated investment supported subject to super majority voting.**
- **Expansions awarded incremental FTRs.**

[3] New York Independent System Operator, Inc Docket No. OA08-13-000, "Order No. 890 Transmission Planning Compliance Filing," Cover Letter Submitted to Federal Energy Regulatory Commission, December 7, 2007, pp. 14-15.

How do the developing transmission investment frameworks integrate with markets?

- **Texas ERCOT and Competitive Renewable Energy Zones**
  - Competitive Construction
  - PUCT Procurement
  - Socialized Cost
- **California and Locationally Constrained Resource Interconnection Facilities**
  - CAISO Procurement
  - Beneficiary Pays Ex Post
  - Socialized Risk
- **Wyoming-Colorado Intertie**
  - Market Decision
  - Beneficiary Pays.

"As part of the Open Season process, the project sponsors had offered up to 850 megawatts of transmission capacity in a public auction. This has resulted in 585 megawatts of capacity purchase commitments from credit-worthy parties. … The project sponsors are optimistic that the remaining 265 megawatts of capacity will be sold. The project sponsors expect to complete the siting, permitting, and construction of the line and begin operation by mid-2013." (WAPA Press Release, August 26, 2008)

- **NYISO Transmission Expansion Proposal**
  - Mixed Market and NYISO Decision. Supermajority vote (80%).
  - Load Beneficiary Pays.

The court has affirmed a cost-benefit standard for transmission evaluation and cost allocation.

> "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. … Rather desperately FERC's lawyer, and the lawyer for the eastern utilities that intervened in support of [FERC's] ruling, reminded us at argument that Commission has a great deal of experience with issues of reliability and network needs, and they asked us therefore (in effect) to take the soundness of its decision on faith. But we cannot do that because we are not authorized to uphold a regulatory decision that is not supported by substantial evidence on the record as a whole, or to supply reasons for the decision that did not occur to the regulators. … We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. … ("we have never required a ratemaking agency to allocate costs with exacting precision"); … If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. … But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." [4]

---

[4] *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted).

"The 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 roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637)

Connecting cost allocation to benefits is a necessary condition for compatibility with an electricity market with decentralized decisions for most investments.

But how can the principle be made operational?

Cost benefit analysis of transmission expansion inherently provides information about the distribution of benefits for use in cost allocation.[5]

5 W. Hogan, "Transmission Benefits and Cost Allocation," Harvard University, May 31, 2011. (www.whogan.com)

Developing rules for efficient transmission infrastructure investment may be easier said than done.

“Last fall, in early October [2012], utilities across the country began filing tariffs with the Federal Energy Regulatory Commission to explain how they will comply with the commission's Order 1000, issued 18 months ago. That order requires all FERC-jurisdictional transmission service providers to participate in regional grid planning, and forces the planners to take account of state and federal policy governing renewable energy. Costs for projects that pass muster in the regional plan must be allocated in a manner "roughly commensurate" with project benefits.” …

“In truth, Order 1000 is proving troublesome even for RTOs. PJM's comply tariff (*FERC Dkt. ER13-198, filed Oct. 25, 2012*) has drawn protests from nearly a dozen state PUCs. But in non-RTO areas, it's harder still. FERC in effect is forcing utilities in non-RTO areas to do many of the same things that RTOs do, but without market pricing or a centralized regional unit dispatch. The comply filings that have come in so far from non-RTO areas raise some key issues:

• ***Active or Passive***: Does Order 1000 require an ex ante assessment of regional needs and solutions, or can planners just sit tight and wait for developers to come forward?

• ***Production Cost Modeling***: Should planners model energy production costs (congestion, fuel use and prices, plant dispatch and capacity factors, etc.) in calculating project benefits?

• ***Sponsor Fitness***: Rules governing capability and qualifications for project developers seem fine, but do they discriminate against non-incumbents?

• ***Public Power Independence***: How to mandate regional cost allocation and yet preserve the FERC-free status of non-jurisdictional participants from the public power sector?”[6]

---

[6] Bruce Radford, “*Very* Roughly Commensurate,” Public Utilities Fortnightly, January 2013, pp. 16-18.

Initial tariff proposals are far from meeting the analytical test posed by the 7th Circuit Court.

> "If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. … But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." [7]

The *very* rough edges of the tariff filings include: [8]

No definition of benefits: E.g., Carolinas. "No benefit metrics, such as production cost, congestion relief, reserve-sharing, or efficiency."

No benefit methodology: E.g., Florida. "Sponsors insist that production cost modeling is impossible using the publicly available data …"

Incomplete benefit methodology: E.g., Northern Tier. "Will recognize three categories of benefit metrics: 1) change in annual capital costs through either deferral or avoidance of a local project; 2) change in "energy" losses (presumably this means line losses); and 3) reduced reserve requirements or access to lower-cost operating reserves. Declines to calculate benefits based on production costs, explaining that filing deadline was too tight to develop congestion cost modeling for a non-RTO area--area-but promises to further explore production cost modeling and come back to FERC in mid-2013 with revisions…"

---

7 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted).

8 Bruce Radford, "*Very* Roughly Commensurate," Public Utilities Fortnightly, January 2013, pp. 20-24.

A transmission infrastructure mandatory cost allocation framework requires a hybrid system that is regional in scope and compatible with the larger market design. FERC Order 1000 proposed principles that are compatible with a larger hybrid system.[9] **The broader framework would include:**

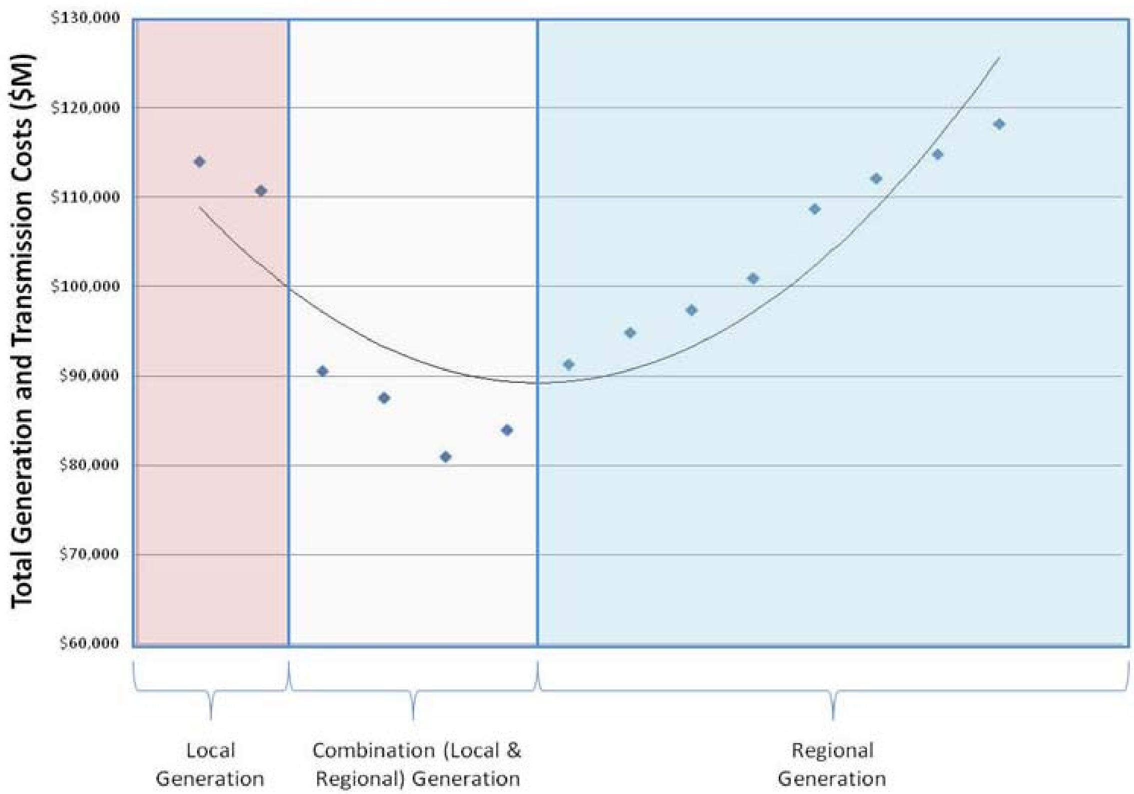
- **Cost Benefit Framework**
  - Gold Standard: Net Benefits > Total Cost
  - Cost Sharing: Commensurable with Benefits
  - Compatible with Larger Market Design
- **Ex ante Estimation and Allocation**
- **Net Benefits = Change in Expected Social Welfare**
  - Counterfactual without contracts
  - Uncertainty and Expected Present Value
- **Approximations of Benefits**
  - Reliability
  - Economic
  - Public Policy
- **Benefit estimates commensurable across categories for projects**
  - Transmission lines affect all categories of benefits
  - Transmission costs cannot be separated into distinct "buckets"

---

[9] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23-000; Order No. 1000, Washington DC, July 21, 2011.

Efficient transmission infrastructure investment interacts with the costs and benefits of types and locations of renewable energy investment.

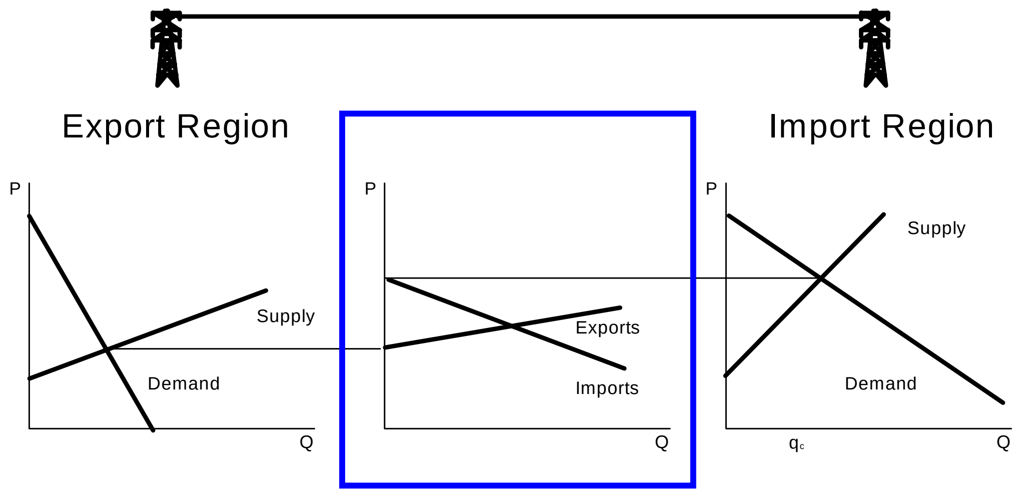
RGOS Zone Scenario Generation and Transmission Cost Comparison[10]



10 Midwest ISO. *Regional Generation Outlet Study*, November 19, 2010, p. 3.

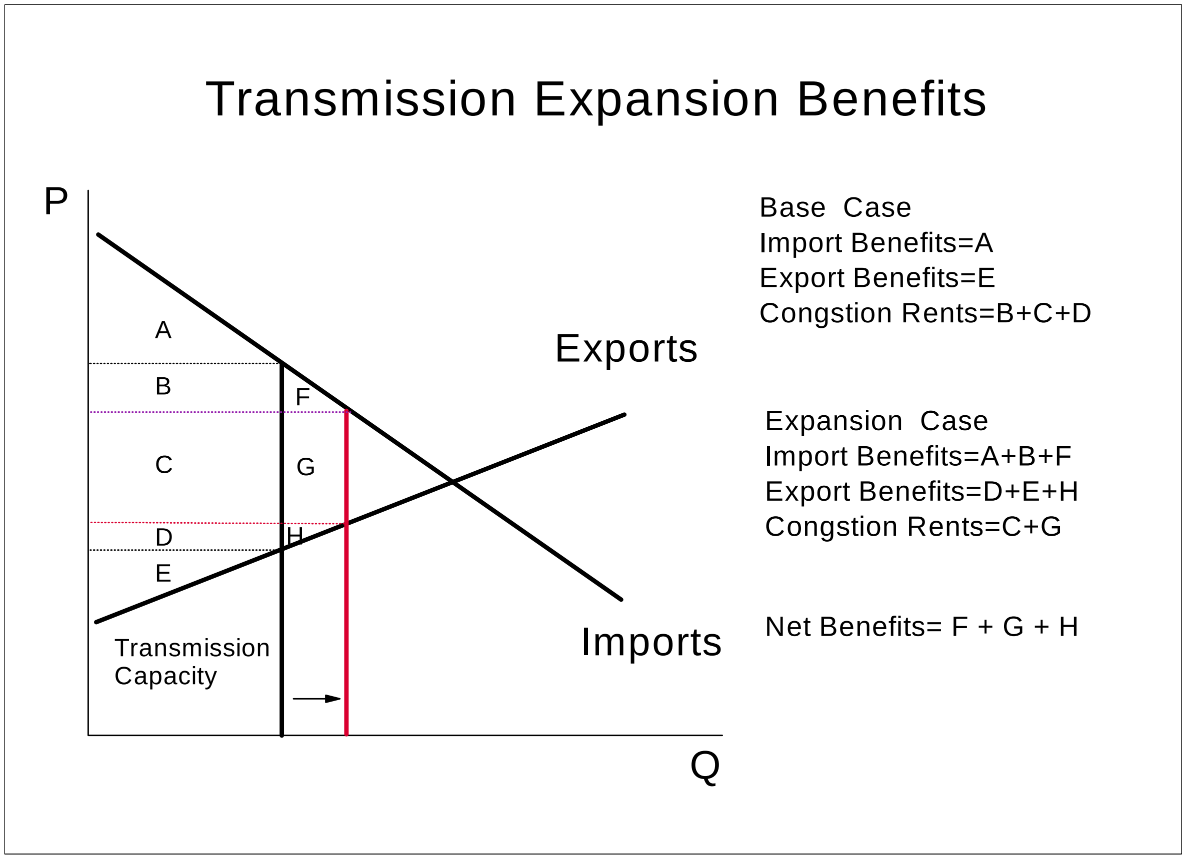
A simple model illustrates a basic framework for defining and classifying the impacts of transmission expansion.

Transmission Between Regions

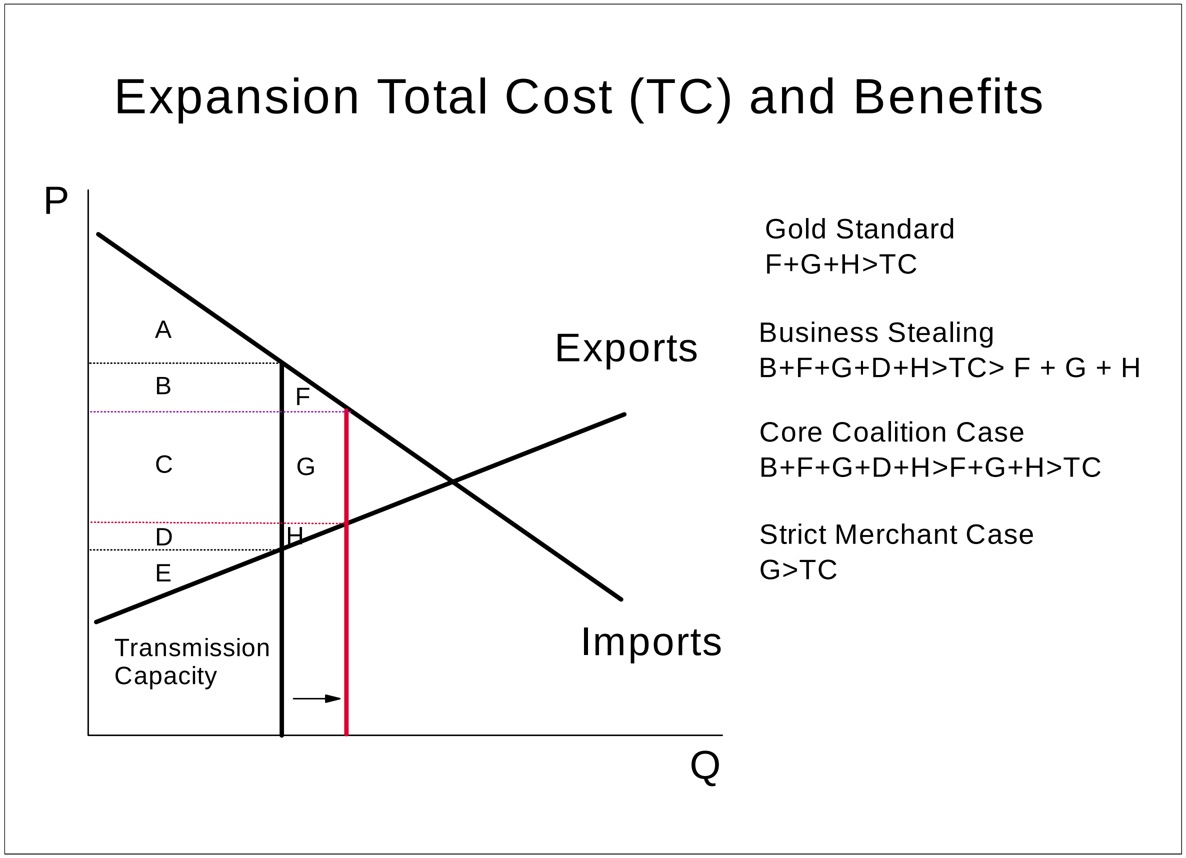


Illustrate benefits for this reduced model

Large scale transmission investments can change export and import volumes and have a material effect on expected market prices.



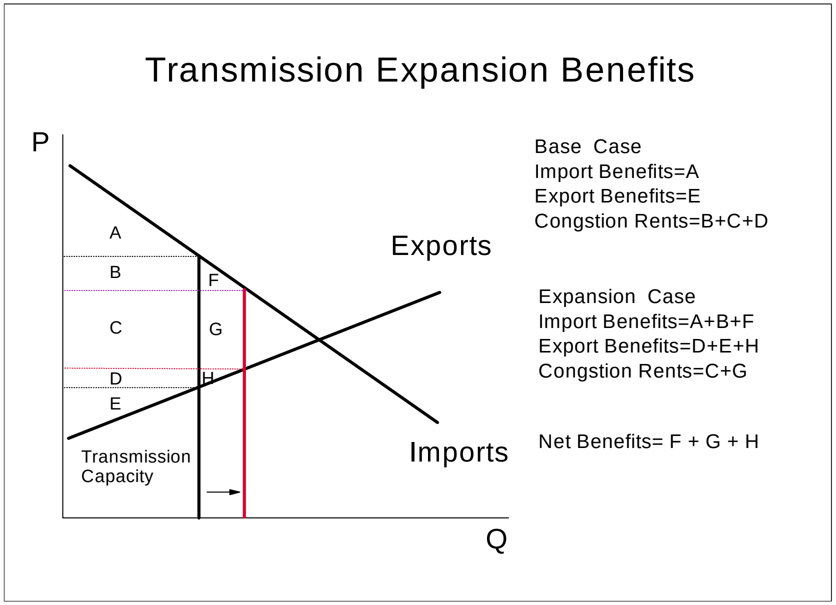
Different conditions can arise in parsing the distribution of benefits and the comparison with the total cost of the transmission expansion.



Past or continuing transmission infrastructure benefits include conflicting definitions that are inconsistent with basic market principles and will create cost allocation problems.

Transmission Benefits

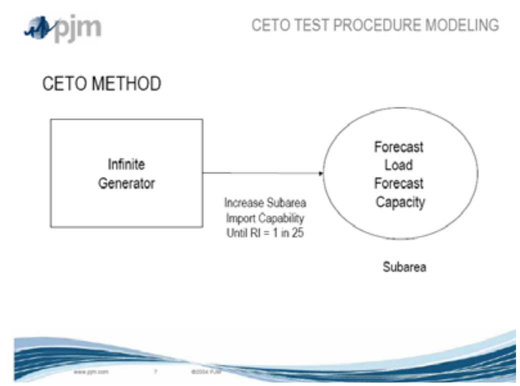
"The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as: Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]. … Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * Change in Load Capacity Payment]." (PJM, "PJM Region Transmission Planning Process," Revision: 16, Manual 14b, Effective Date: November 18, 2010, p. 75.)



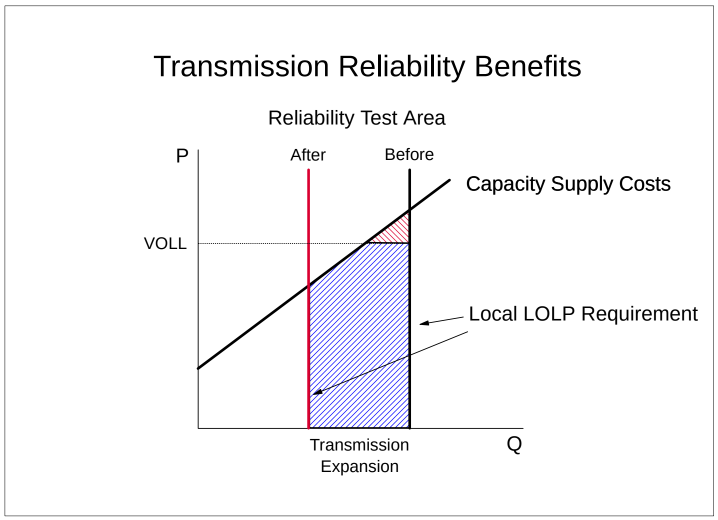
"Market Congestion Benefit: 70% * Adjusted Production Cost Savings + 30% * Load Cost Savings." (MISO, "2010 Transmission Expansion Plan," Nov. 30, 2010, p. 31.)

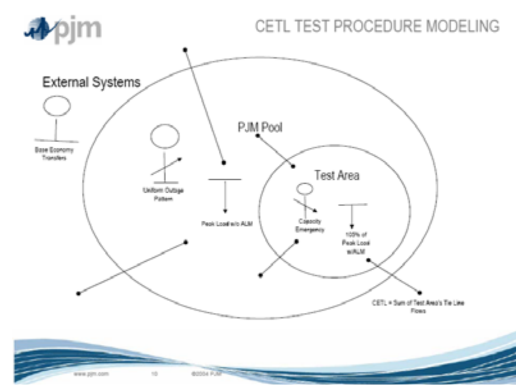
"Load Cost Savings where load cost represents the annual load payments, measured by projections in hourly load weighted LMP: Load cost savings and Adjusted Production Cost savings are essentially two alternative benefit measures to address a single type of economic value and are not additive measures. Load cost savings were not used to calculate the total value of the RGOS plans in MTEP10. … Value of transmission plan (per future) = Sum of values of financially quantifiable measures = Adjusted Production Cost savings + Capacity loss savings + Carbon emission reductions." (MISO, "2010 Transmission Expansion Plan," Nov. 30, 2010, p. 153-154.)

Efficient transmission infrastructure investment includes estimated reliability benefits.



- Reliability modeling in a cost benefit framework.
    - o Reliability constraint and cost minimization.
    - o Change in value of expected curtailments at VOLL.
    - o PJM CETO/CETL method approximates expected curtailments.

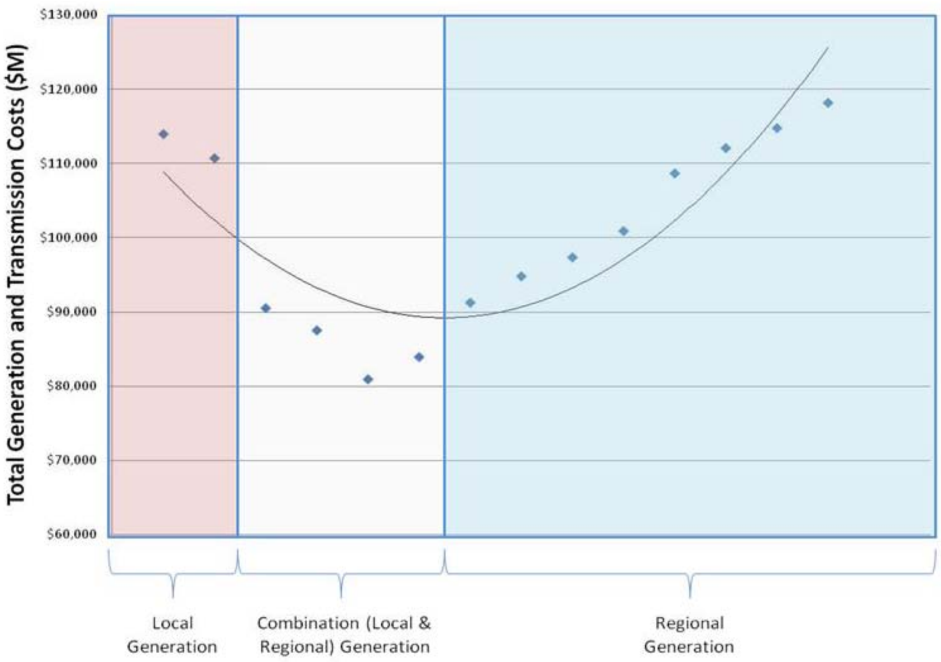




- For example, this is not the same as a DFAX cost allocation "Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all generation external to the study area and the sink is the peak zonal load for each Transmission Owner within the study area. Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading." (PJM Manual 14B, p. 34)

Efficient transmission infrastructure investment includes benefits of meeting public policy objectives or constraints.

- **Environmental Constraints.** With caps or prices on emissions, environmental costs would be internalized with the cost of generation expansion and dispatch. Public policy objectives become part of standard economic cost benefit analysis.
- **Renewable Portfolio Standards.** The Midwest "RGOS Zone Scenario Generation and Transmission Cost Comparison" provides an example of including public policy constraints. States established the anticipated targets, including local generation requirements. The scenarios considered different mixes of generation and transmission investment subject to the constraint of meeting the RPS mandates.



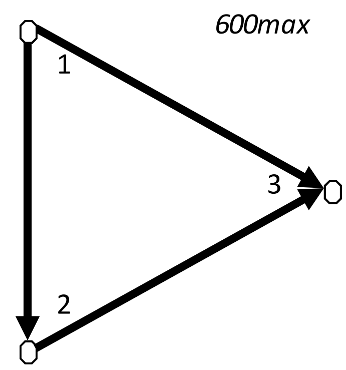
- **Transmission Benefit Calculation.** The benefit of transmission expansion does not include the benefit of the RPS mandate. Evaluating the benefits of public policy is different and more difficult than evaluating the benefits of transmission expansion in meeting public policy objectives.

Transmission Expansion Example

The simplest network to illustrate locational interactions has three lines and nodes. Consider a lossless approximation with identical lines and one constraint.

The simple supply curves are flat up to the maximum quantity. Generators G1, G4 and G6 are renewable sources. There is a renewable portfolio standard (RPS) of 50% of the load at location 3. The demand curves are price sensitive at locations 1 and 2, but fixed at location 3. The transmission constraint applies to the line between locations 1 and 3.

	P	Max
G1	50.00	1000
G2	40.00	500
L1	75	300



P	Max	
70.00	500	G5
150.00	2000	G6
500	1800	L3

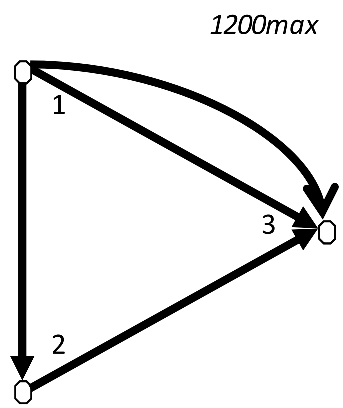
	P	Max
G3	50.00	500
G4	60.00	500
L2	60	50

This network would support Financial Transmission Rights (FTRs) for 900 MW between locations 1 and 3.

The possible network expansion has identified an additional line between locations 1 and 3 to double the capacity on this segment.

The same supply and demand conditions apply. The expanded grid could provide 1500 MW of FTRs between locations 1 and 3.

	P	Max
G1	50.00	1000
G2	40.00	500
L1	75	300



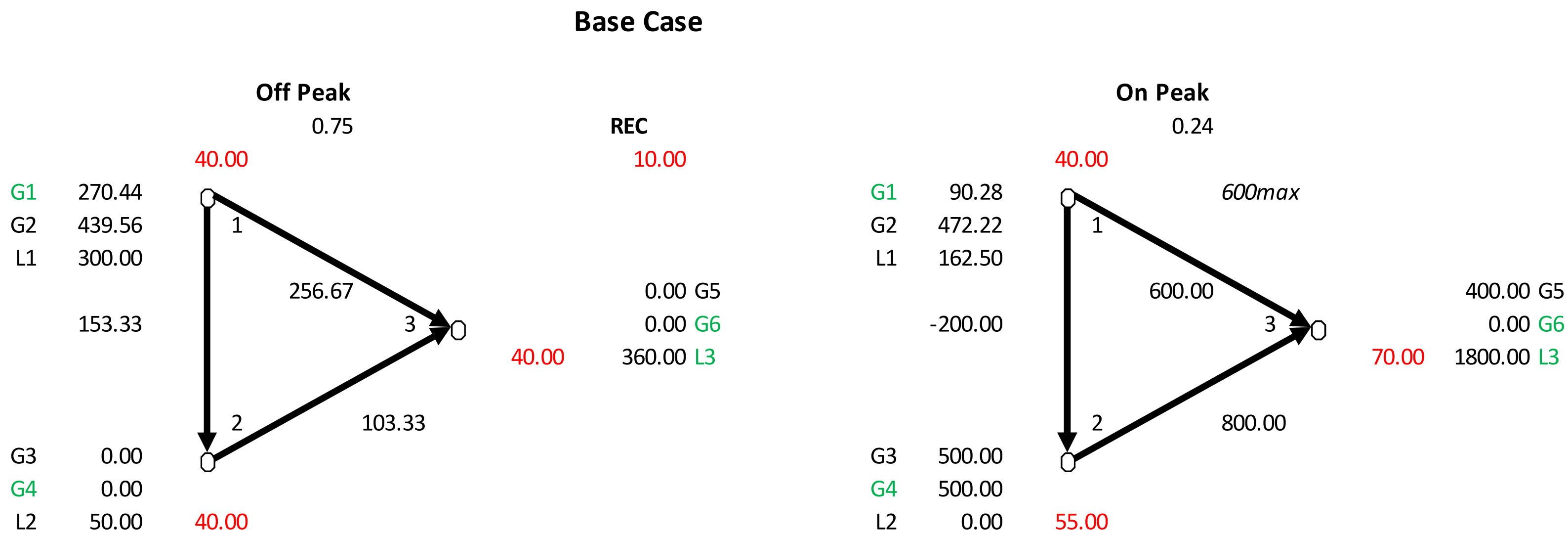
P	Max	
70	500	G5
150	2000	G6
500	1800	L3

	P	Max
G3	50.00	500
G4	60.00	500
L2	60	50

The expanded dispatch would change the patterns of costs and benefits. (Caution: This is a conceptual illustration and does not represent any particular transmission expansion plan.)

The future is uncertain, and conditions differ across different scenarios. The use of two economic scenarios, for peak and off peak conditions, illustrates the idea. A third low probability case proxies for reliability standards.

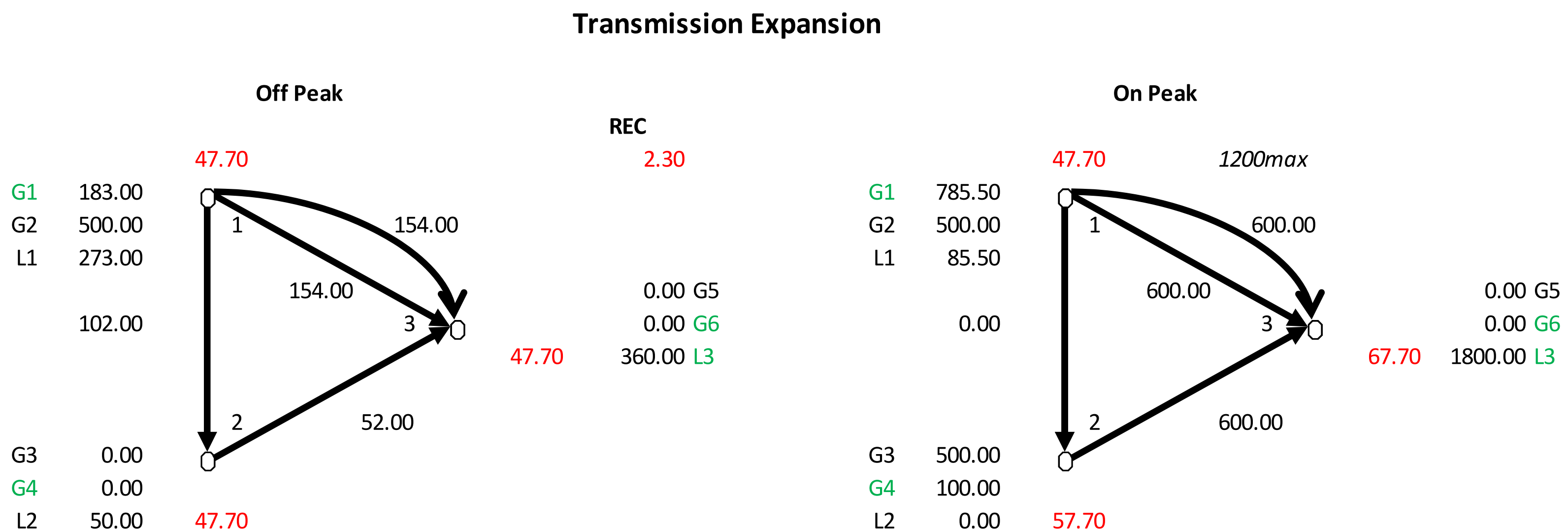
The example ignores contingency constraints, but additional operating constraints would be incorporated as done now in dispatch and planning models. The RPS standard is an expected value constraint across all scenarios and produces a price for a renewable energy credit (REC). The prices and flows include:



The off-peak case has no congestion. The on-peak case shows congestion and this limits access to lower cost generation, including renewables. The REC price is assumed to be paid by RPS load at location 3, and received by the various renewable generators.

The expansion case uses the same economic scenarios, probabilities and RPS requirements.

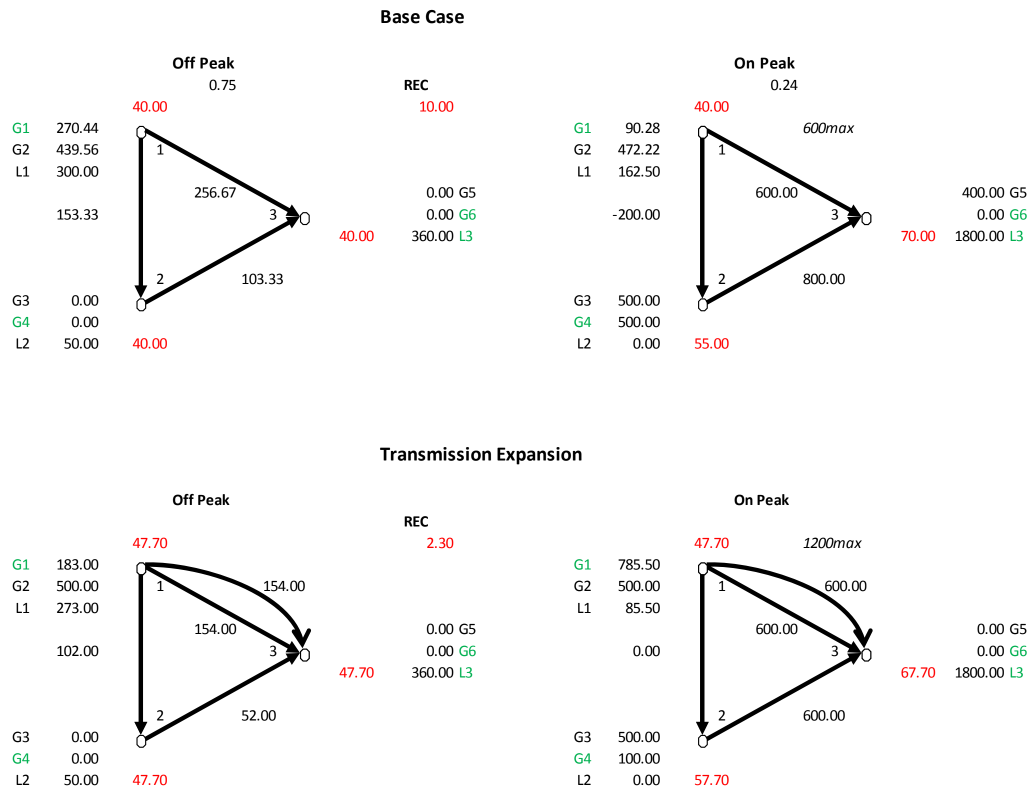
The increase in transmission capacity affects the dispatch, costs and benefits.



Prices change for all scenarios, including the REC price.

A comparison of the base case and expansion case provides the expected costs and benefits in aggregate and for different loads, generators and FTR holders.

The details at each location amount to unpacking the “bid production” costs and revenues. These are the individual consumer and producer surplus, and congestion, calculations.



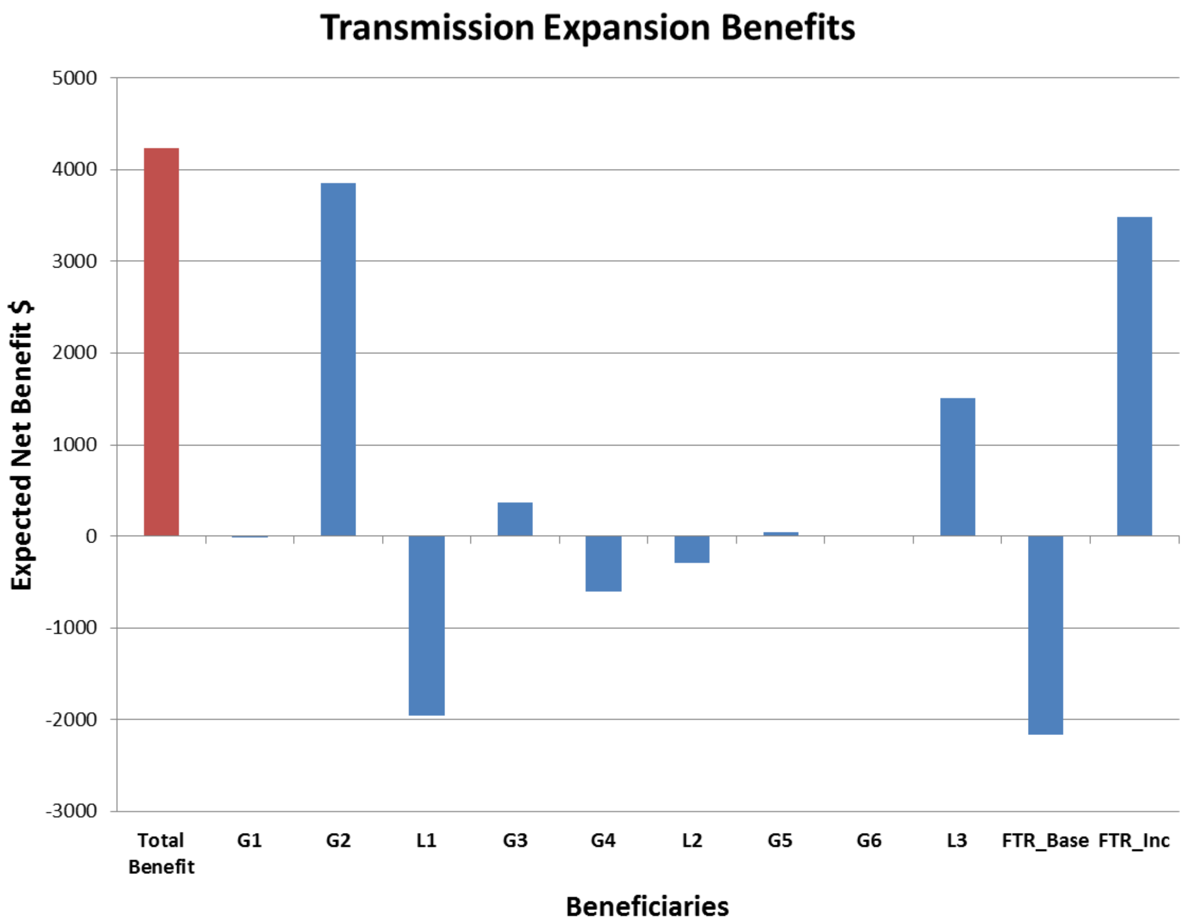
The details are tedious but straightforward.

The total change between cases identifies the total expected benefits. This includes economic benefits, the cost of the RPS, and the cost of meeting the reliability standard. The single line affects all categories of costs and benefits.

The total benefits would be compared with the total cost of the transmission line expansion. The individual benefit estimates include transfer payments resulting from the change in prices.

The transmission line investment cost is not put in buckets defined by type of benefit.

The distribution of the total of economic, reliability and public policy benefits is not uniform. The allocation of the transmission expansion costs could utilize this distribution of expected benefits.



Efficient transmission infrastructure investment inherently requires forecasts of conditions for long-lived infrastructure. This presents challenges for cost benefit analysis and cost allocation.

- **Defining the Horizon of Analysis.** This is a standard problem in planning, but will be more important to the extent it affects cost allocation.
- **Representing Uncertainty.** Scenarios and sensitivity analysis will be more important. And benefits need to be aggregated as expected benefits, probability weighted across anticipated outcomes. This is not new, but cost allocation will make this both more contentious and more necessary.
- **Choosing the Counterfactual.** This seems straightforward in a static one-shot framework. It becomes more difficult in the dynamic setting that includes future transmission investments.
- **Harmonizing Investment Decisions.** The regional planning function for transmission is not the same thing as integrated regional planning of old. Even if the plan mandates certain transmission investments, the complementary decisions on generation and load will be decentralized.
- **Eliciting Support of Beneficiaries.** "The proposed cost allocation mechanism is based on a 'beneficiaries pay' approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote." (New York Independent System Operator, Inc Docket No. OA08-13-000, "Order No. 890 Transmission Planning Compliance Filing," Cover Letter Submitted to Federal Energy Regulatory Commission, December 7, 2007, pp. 14-15.)
- **Other?**

William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Exelon, Financial Marketers Coalition, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Koch Energy Trading, Inc., LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Company, Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Twin Cities Power LLC, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).