ALLOCATING COSTS COMMENSURATE WITH MULTIPLE TRANSMISSION BENEFITS

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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.

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[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.

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.[2] **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.

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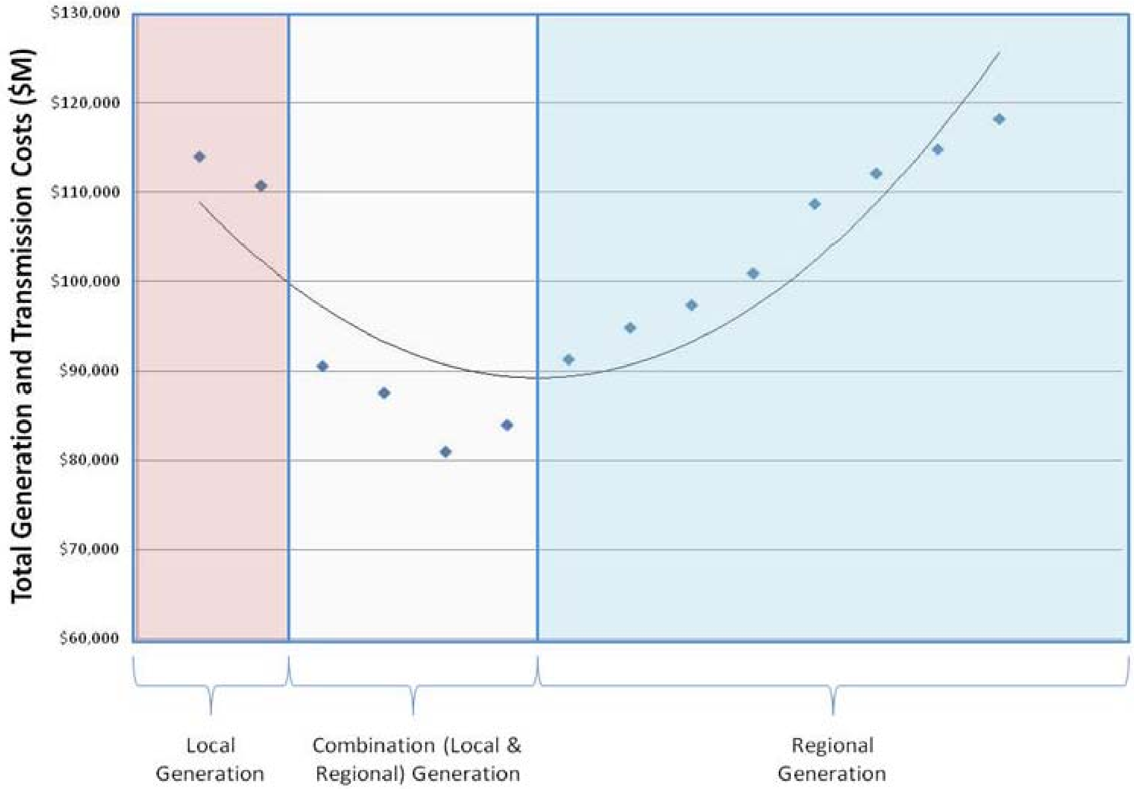
[2] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23-000; Order No. 1000, Washington DC, July 21, 2011.

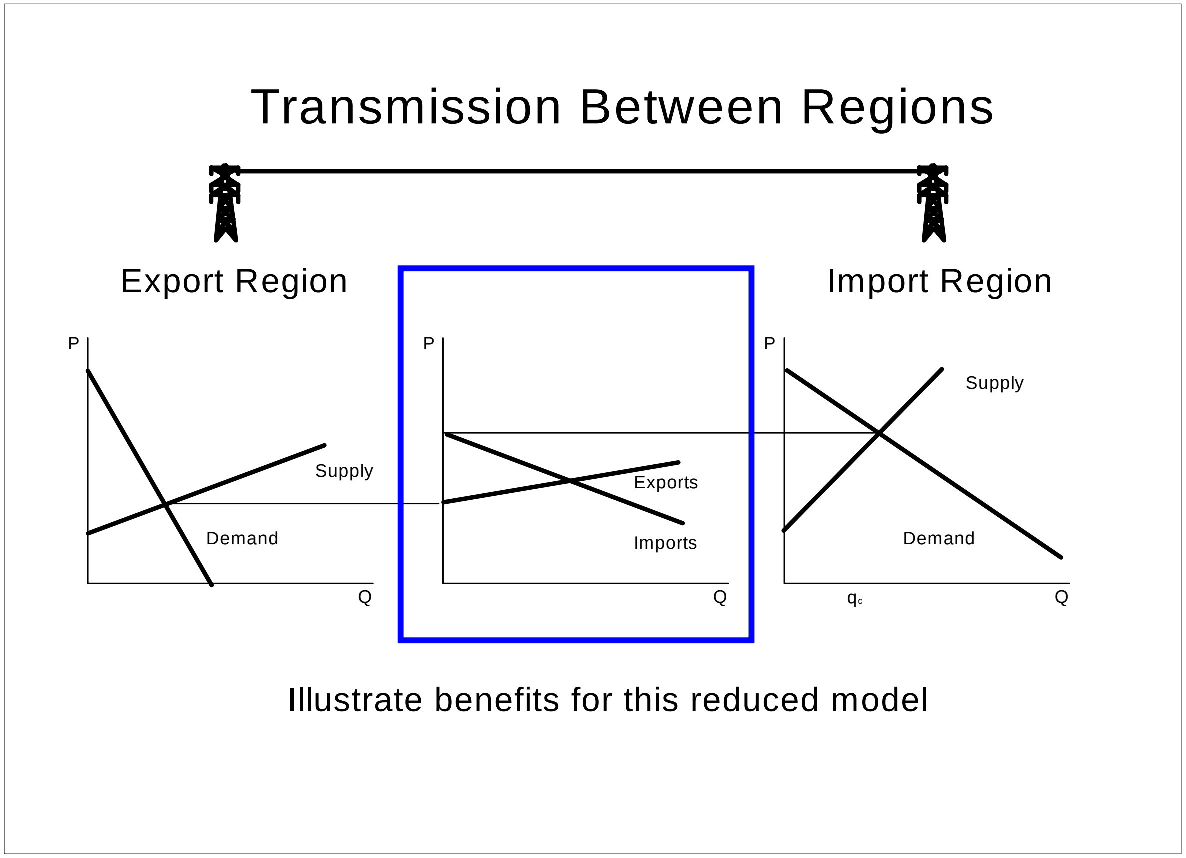
Efficient transmission infrastructure investment interacts with the costs and benefits of types and locations of renewable energy investment.

RGOS Zone Scenario Generation and Transmission Cost Comparison[3]

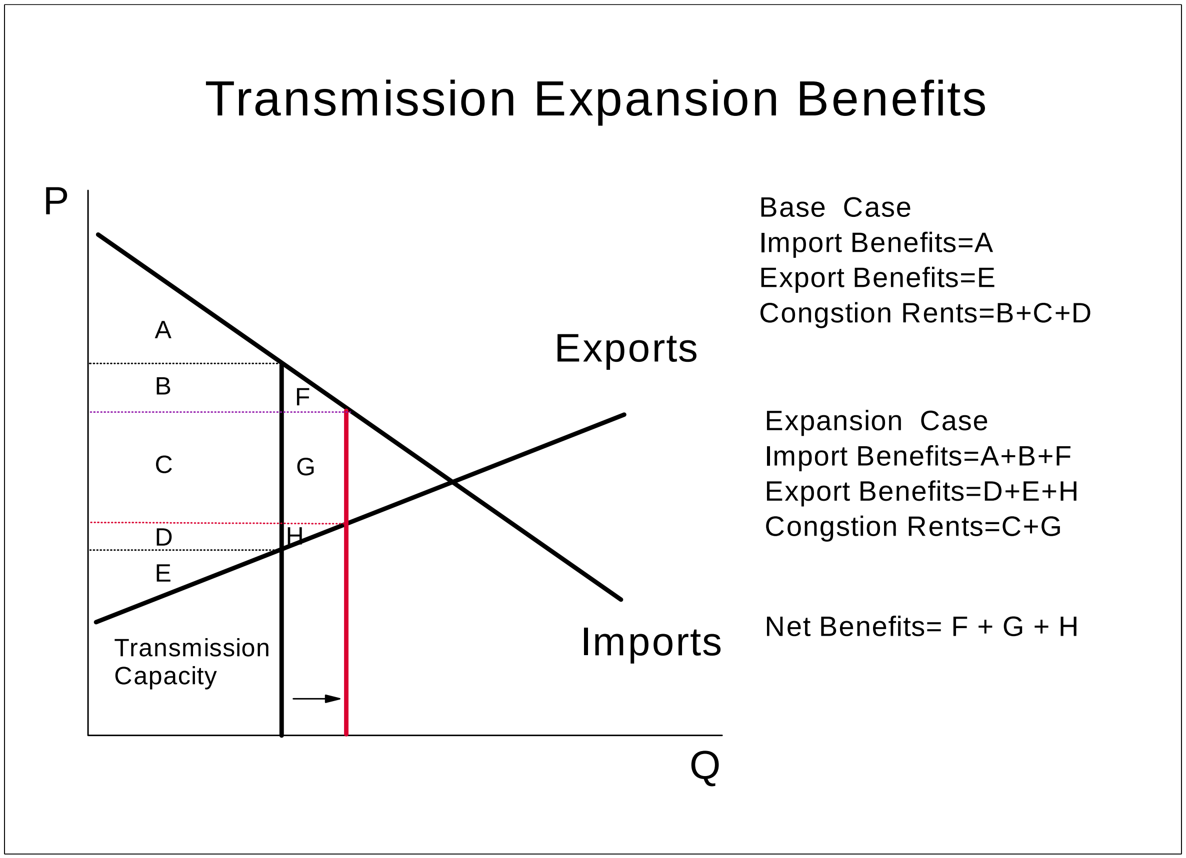


3 Midwest ISO. *Regional Generation Outlet Study*, November 19, 2010, p. 3.

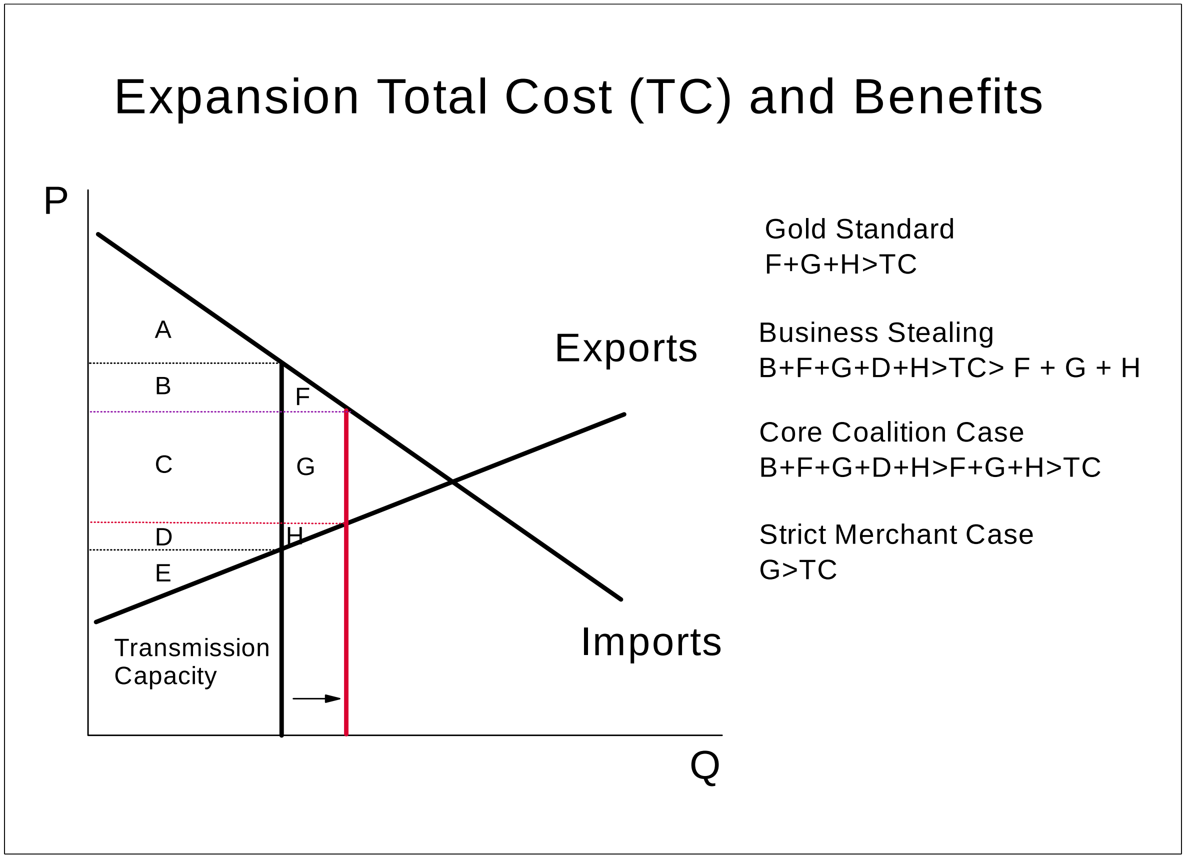
A simple model illustrates a basic framework for defining and classifying the impacts of transmission expansion.



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



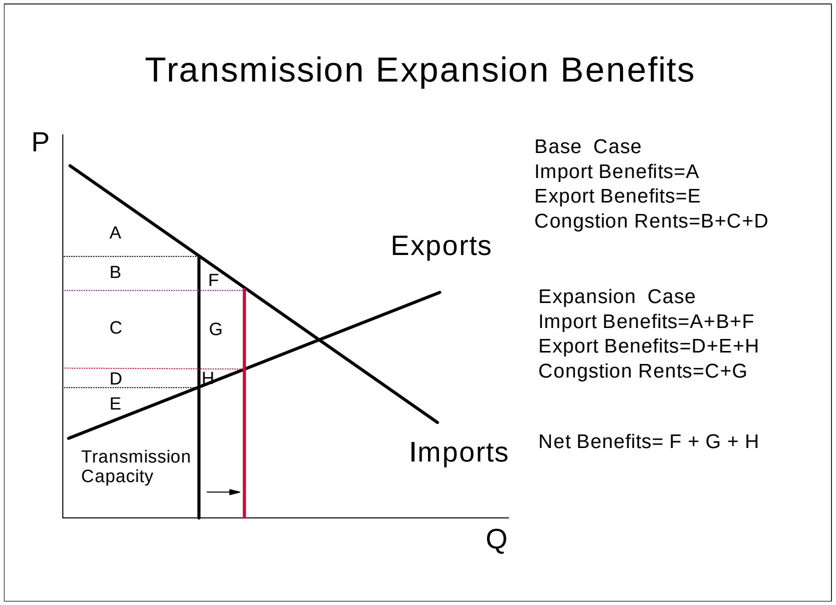
Different conditions can arise in parsing the distribution of benefits and the comparison with the total cost of the transmission expansion.



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

Transmission Benefits

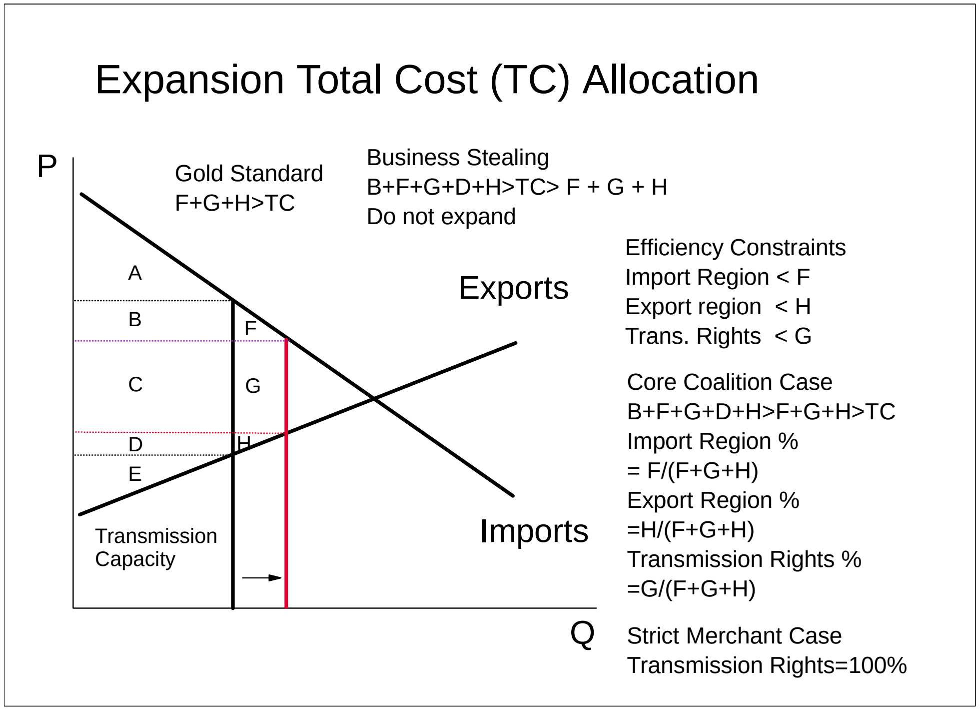
"The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as: Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]. … Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * Change in Load Capacity 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.)

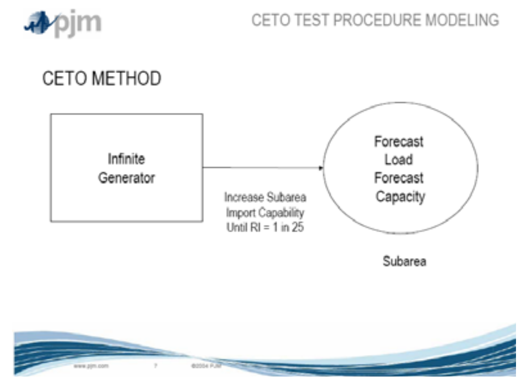
"The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637) Cost benefit analysis of transmission expansion inherently provides information about the distribution of benefits for use in cost allocation.[4]

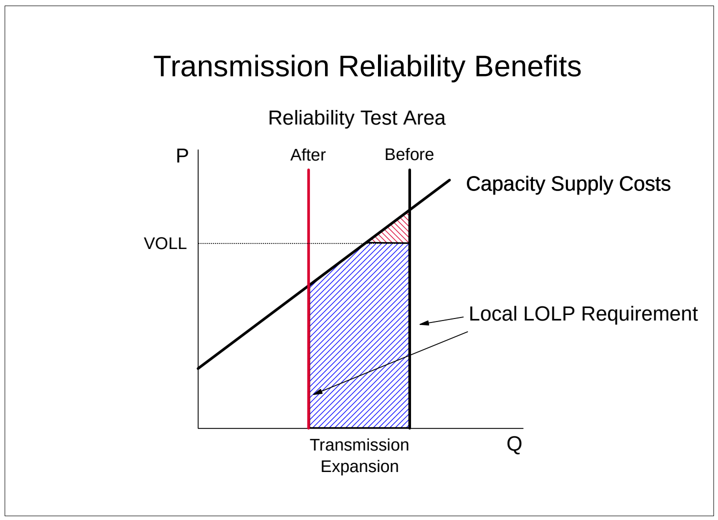


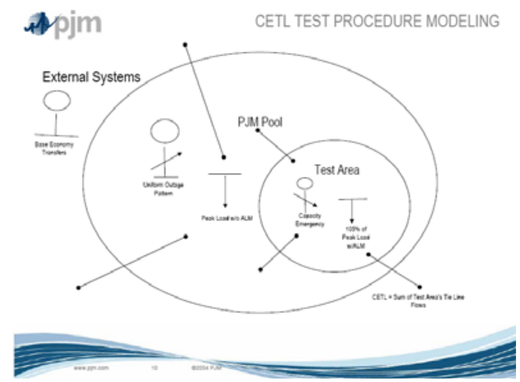
4 W. Hogan, "Transmission Benefits and Cost Allocation," Harvard University, May 31, 2011. (www.whogan.com)

Efficient transmission infrastructure investment includes estimated reliability benefits.

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



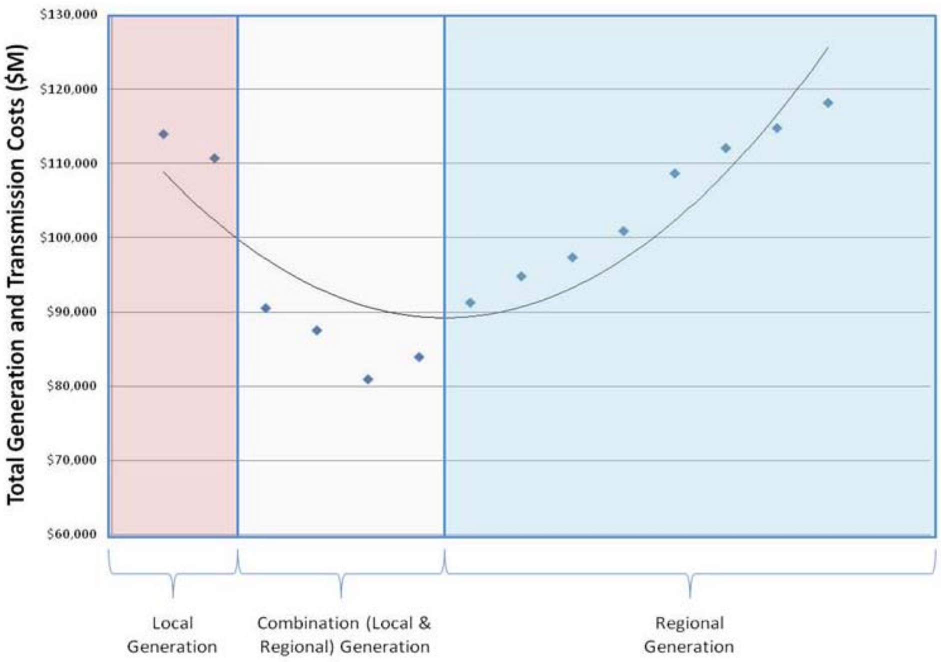




- For example, this is not the same as a DFAX cost allocation "Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the 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.

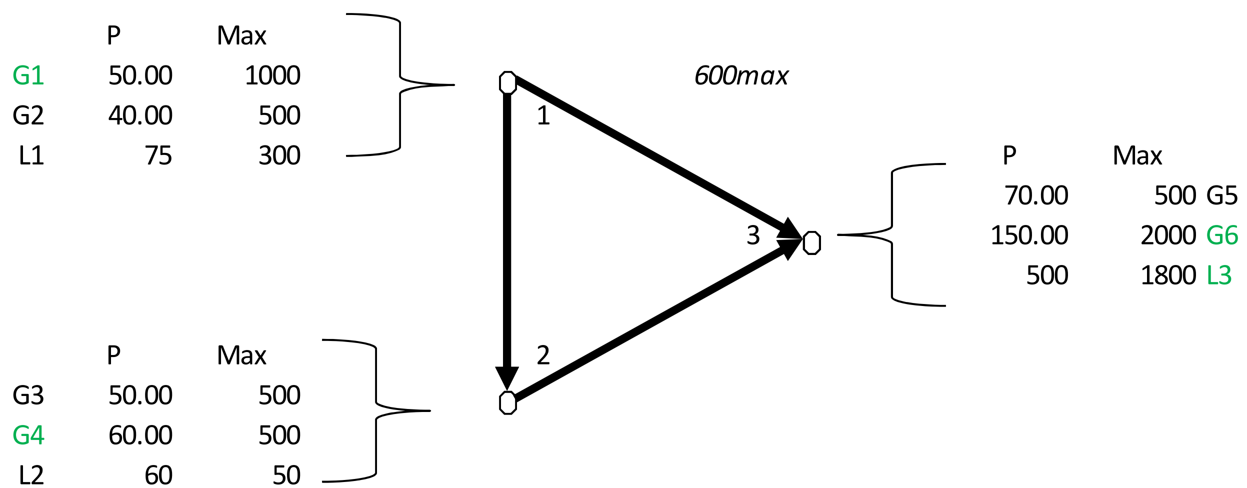
- **Environmental Constraints.** With caps or prices on emissions, environmental costs would be internalized with the cost of generation expansion and dispatch. Public policy objectives become part of standard economic cost benefit analysis.
- **Renewable Portfolio Standards.** The Midwest "RGOS Zone 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.

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

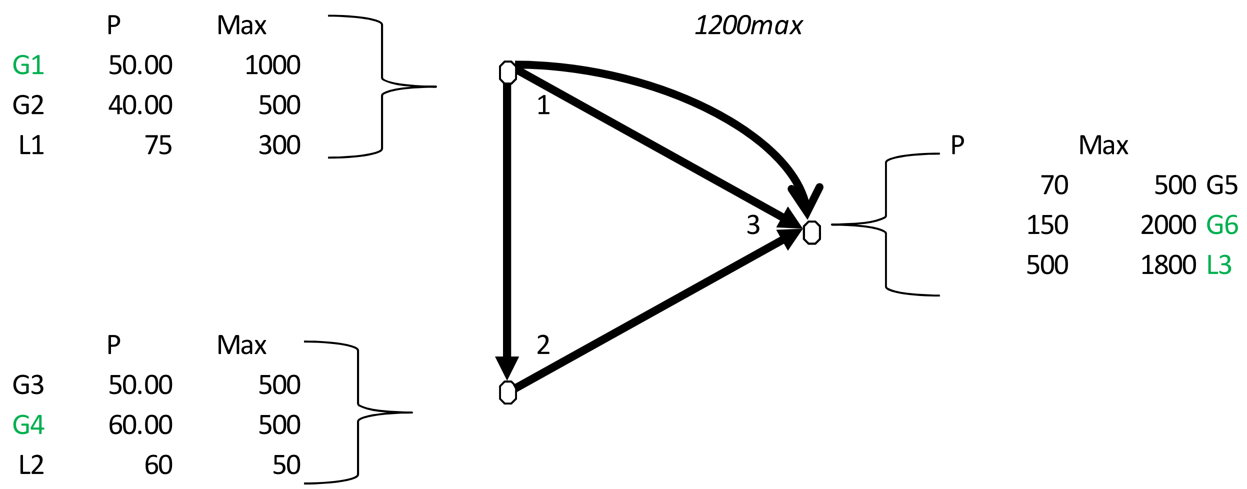
The simple supply curves are flat up to the maximum quantity. Generators G1, G4 and G6 are renewable sources. There is a renewable portfolio standard (RPS) of 50% of the load at location 3. The demand curves are price sensitive at locations 1 and 2, but fixed at location 3. The transmission constraint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



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.

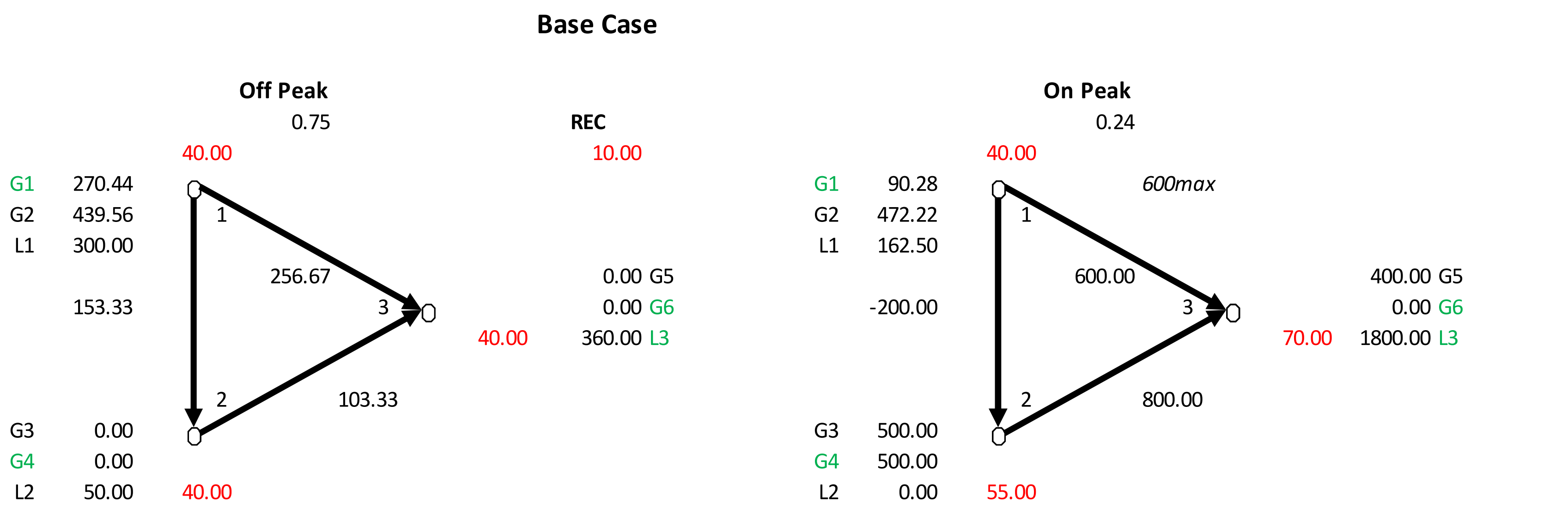
The same supply and demand conditions apply. The expanded grid could provide 1500 MW of FTRs between locations 1 and 3.



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.

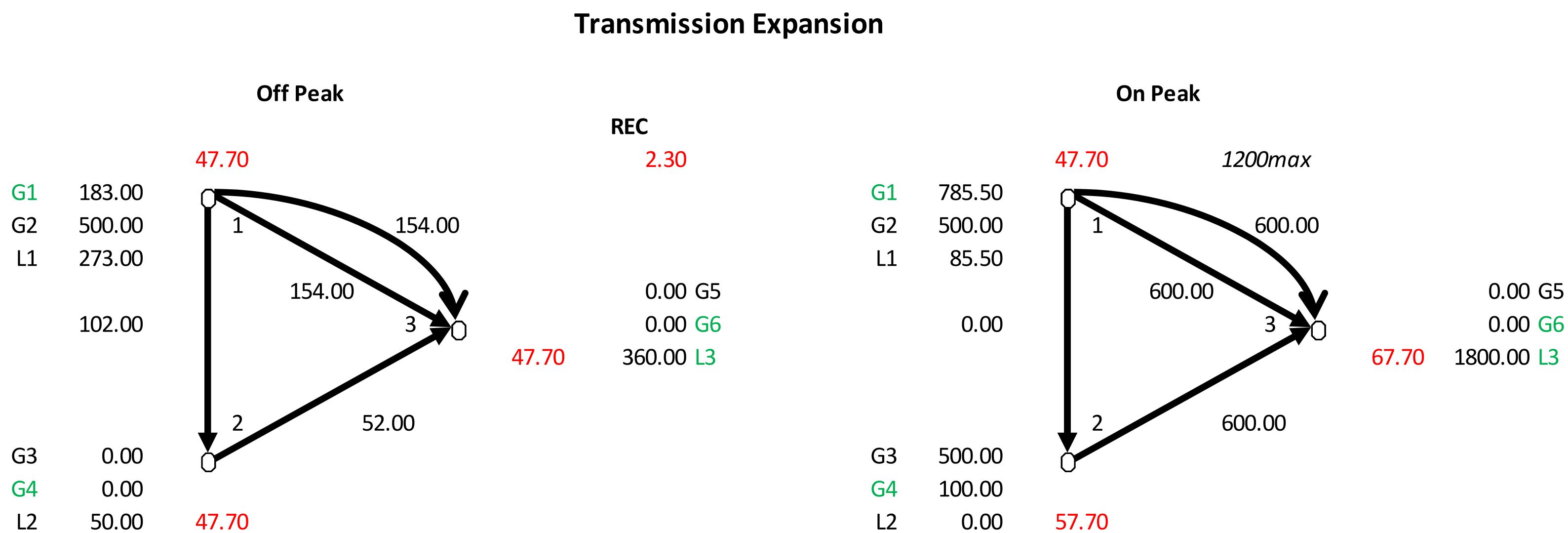
The example ignores contingency constraints, but additional operating constraints would be incorporated as done now in dispatch and planning models. The RPS standard is an expected value constraint across all scenarios and produces a price for a renewable energy credit (REC). The prices and flows include:



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.

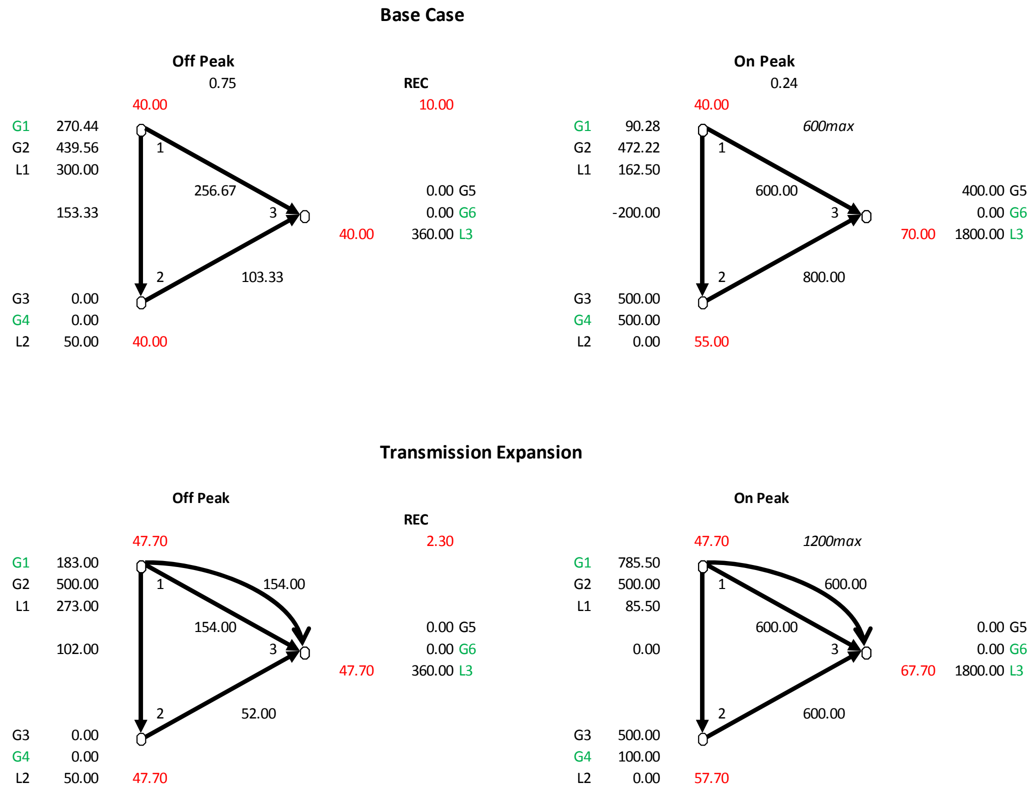
The increase in transmission capacity affects the dispatch, costs and benefits.



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.



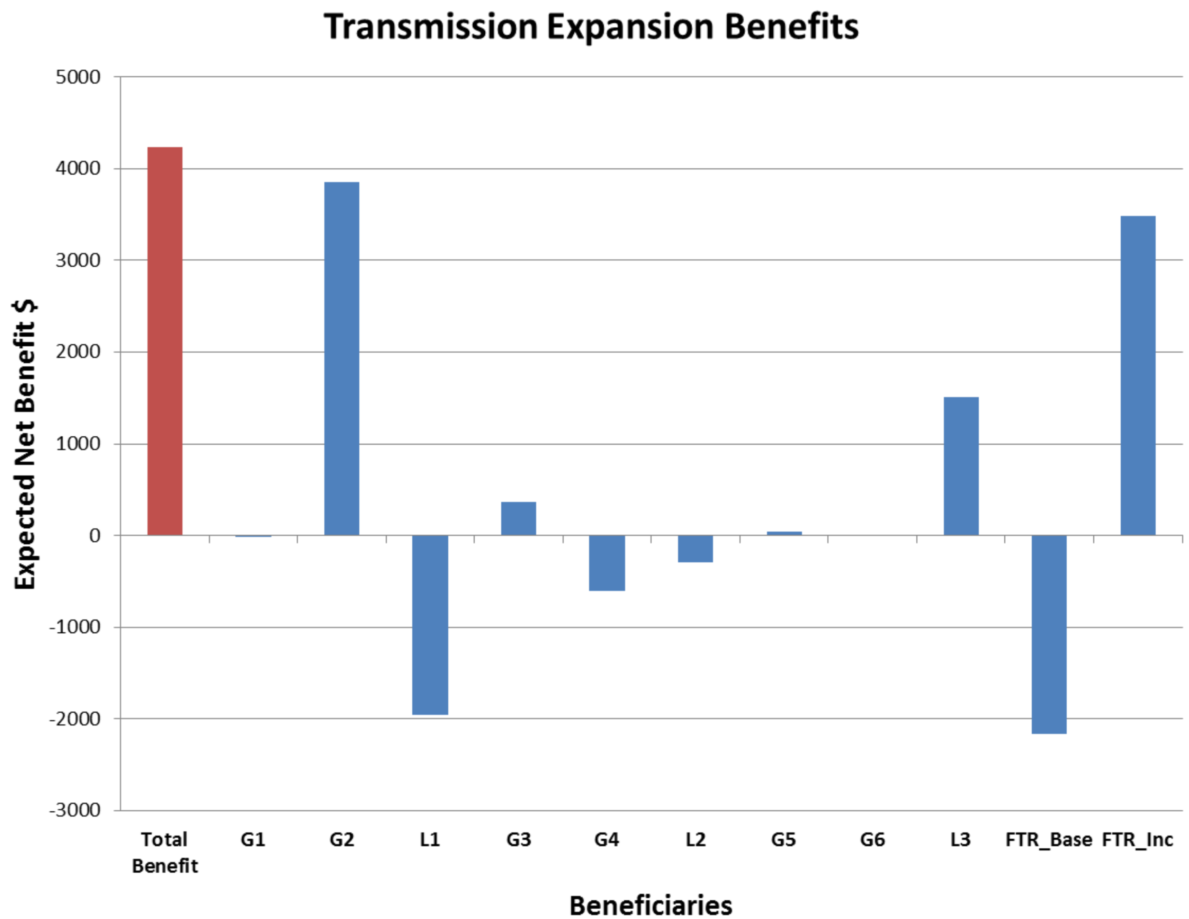
The details are tedious but straightforward.

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 Uncertianty.** 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.
- **Harmoninzing 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?**

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