Bilateral Contracting for Electricity in Ghana with Competition and Open Access

Volta River Authority

Mövenpick Ambassador Hotel Accra

August 24, 2012

First Principles Economics, LLC

Organization/Agenda – 1st Day of the Workshop

Our objective is to work through the implications of the Government's policies to create a competitive wholesale electricity sector. Specifically we want to discuss with our customers how (1) competition and (2) open access will affect bilateral contracting and how that has lead to a new Power Supply Purchase Agreement.

The agenda for the 2-day workshop is:

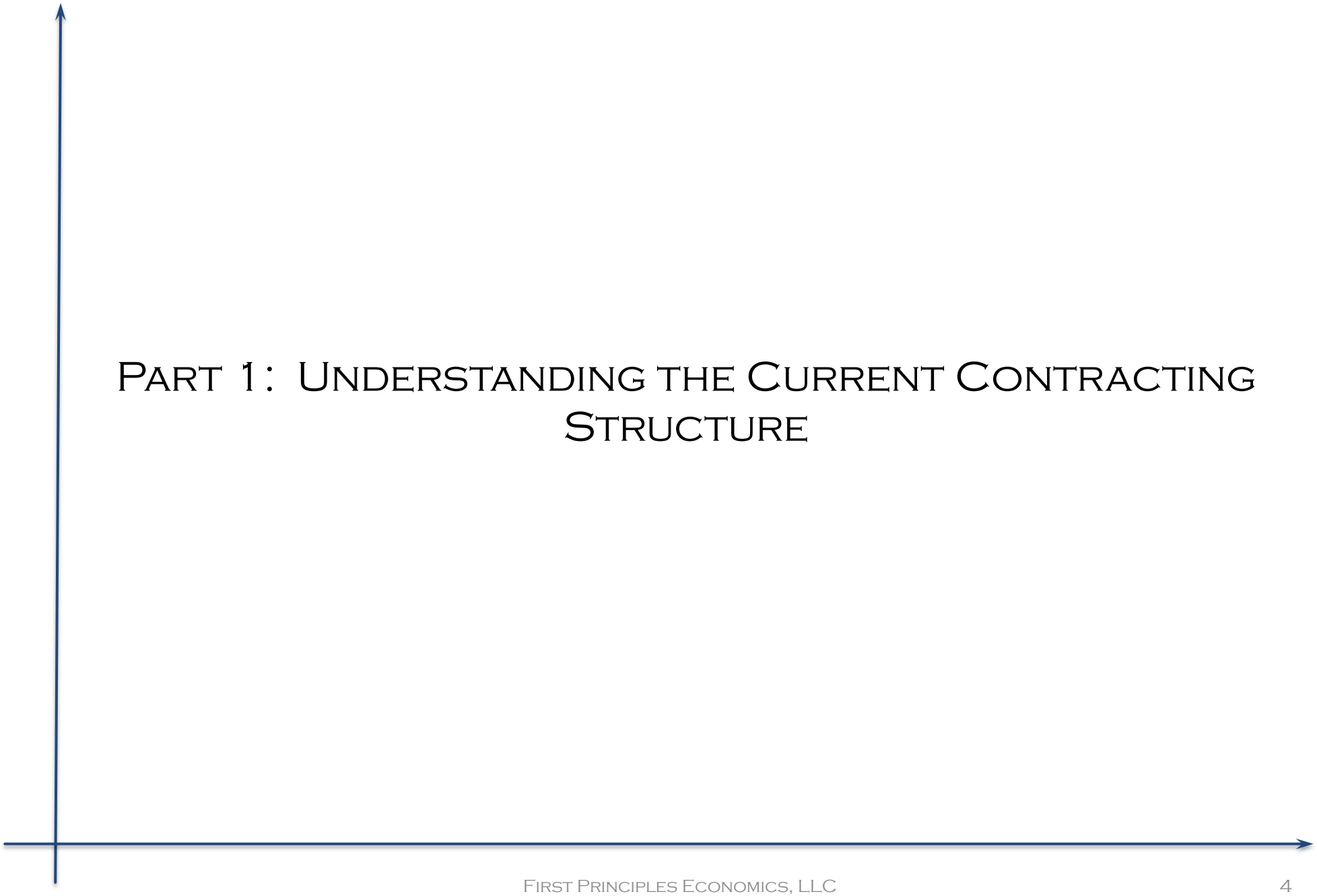
Day 1:

8:30 – 9:00	Registration of Participants
9:00 – 9:15	Welcome Statement by Chief Executive of VRA.
9:15 – 10:30	Part 1 - Introductory comments and Existing Power Supply Contracting Structure
10:30 – 10:45	Cocoa/Coffee Break
10:45 – 12:00	Part 2 – Effects of competition and open access on the contracting structure.
12:00 – 13:00	Lunch
13:00 – 14:30	Part 3 – Allocating transmission capacity and access to the dispatch function.
14:30 – 14:45	Cocoa/Coffee Break
14:45 – 16:00	Part 4 – How the new structure of the Industry (i.e. competition, open access, GRIDCo, etc) leads to a new contracting paradigm
16:00	End of the first day of the workshop.

Organization/Agenda – 2nd Day of the Workshop

Day 2:

8:30 – 9:00	Arrival of Participants
9:00 – 9:30	Part 5 Review of the 1st Day Presentation
9:30 – 11:00	Part 6 – International experience – how contracting has changed as a result of reform in other countries/regions.
11:00 – 11:30	Cocoa/Coffee Break
11:30 – 13:00	Part 7 Presentation and discussion of the Draft Power Supply Purchase Agreement.
13:30 – 14:00	Discussion, questions and answers on Draft Master PSPA
14:00	Lunch
16:00	End of the workshop



Part 1: Understanding the Current Contracting Structure

Hunt and Shuttleworth…

In the preface to their book *Competition and Choice in Electricity*, Hunt and Shuttleworth relay the following comment made by a utility regulator:

> *"I grew up in a world of planning and marginal cost pricing. I know how to make tariffs and calculate rates of return…I know how to choose the next supply source and how to estimate demand…I can do cost allocations…But in this new world of competition, I seem to need to know about markets and contracts and risk allocation, and how to structure an open transmission system."*

Introductory Comments

Since 1995 with the initiation of the Power Sector Reform Program, the Government of Ghana has pursued a broad policy with respect to electricity designed to transition to a competitive wholesale market. In particular, LI 1937 specifies that there will be a wholesale electricity market in:

> *4....(2) The operator of the wholesale electricity market shall ensure the procurement and dispatch of electricity from **ANY** facility of a wholesale supplier to a bulk customer and distribution company in a fair, transparent and non-discriminatory manner.*

To date the policies appear to have had success:

- "Private investors have responded to efforts by the government to create a viable power market. Since Ghana enacted the Energy Commission Act, 1997, Act 541, five private entities have announced or are at various stages of construction of a total of 960 MW of new generation facilities." Ghana Power Reliability Report 2010, p. 5.

Why are we here?

The industry is in the process of moving from an institutional structure where the wholesale activities of generation and transmission were carried out by a vertically integrated monopoly to a competitive structure with competition between generators.

Bilateral contracting between VRA and its customers has historically been the only way to contract for power in Ghana. Allowing competition in the generation sector and the resulting need to separate transmission from generation lead to changes in bilateral power contracts. However, despite the changes in the industry, bilateral contracting will continue to be the primary method of transacting. We have three objective for the workshop:

1. To show our customers that the type of contract that is in place now reflects a specific institutional structure, i.e. one that was based on vertical integration and no competition.
2. To explain to our customers how and why the implementation of open access and competition must change the contracting structure.
3. To introduce, explain and discuss the new structure of the PSPA.

The Core of the Issue...

...can be found in the language used in our existing PSPA. In particular, the basic structure of the current PSPA is that VRA will physically generate and deliver electrical power and energy to our customers at a designated delivery point. This is evident from the following sections of an actual PSPA – none of which can be performed by any single generator in a competitive open access environment:

2.1.1 Sale of Electrical Power and Energy

The Seller shall within the terms of the Agreement deliver and sell in each Contract Year a maximum demand of .....MW and average demand of .....MW of electrical power and energy to the Purchaser at the designated connection point(s) on the NITS...

2.1.2 Passage of Risk and Title

The Seller shall deliver electrical power and energy to the Purchaser at the Connection Points on the NITS as agreed in the Connection Agreement between the Seller and the designated Transporter and the electrical power and energy shall be delivered in accordance with the TSA between the Purchaser and Transporter. The risks and title thereof shall be deemed to have passed to the Purchaser.

3.4

Subject to any scheduled and unscheduled maintenance requirements and events of force majeure, which may prevent the Seller from doing so, the Seller shall deliver the electrical power and energy as commercially continuous twenty-four (24) hour every day in the year except as otherwise provided in this Agreement.

5.0 Pricing

The tariff and tariff adjustment for guaranteed electrical energy supply shall be as per Annex 1. The charge for electrical power and energy does not include any duty and tax.

8.2 Accuracy of Forecasts

If, the power consumption by the Purchaser is higher than 5% of the annual forecast, the Seller reserves the right to charge the actual verifiable marginal cost for the additional electrical power and energy...

Characteristics of the Existing Bilateral Contract Structure

The current contracting structure reflects the fact that VRA was previously a vertically integrated monopoly with ownership and control of all generation and the high voltage transmission system. As such, consumers had no choice over who their provider would be.

I. The most important aspect of this structure was that VRA was able to make unilateral decisions regarding both generation and transmission.

II. For every dispatch period, VRA was able to jointly decide how to use their generation facilities while managing transmission constraints and maintaining reliable grid operation.

   A. Thus VRA alone decided which facilities would be used to provide energy and ancillary services as well as where needed generation capacity would be held.

III. As the monopoly generator who simultaneously operated the transmission system, VRA was structurally capable of managing a wide range of risks and costs.

   A. VRA could enter into bilateral contracts with their customers for "delivered energy", i.e. VRA would provide power to a customer at a certain point on the grid for an agreed upon price and time period.

   B. Because they were a vertically integrated monopoly VRA could internalize all the decisions necessary to fulfill their terms of the contract.

A Generic Model of Current Bilateral Contracting under Monopoly Generation and Transmission

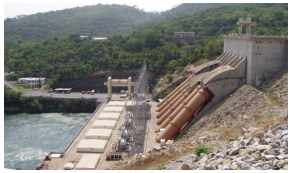
I. In the simplified network on the right, there are 2 generators (G1 & G2) at two different locations that are both owned by VRA.

II. VRA also owns and operates the three transmission lines.

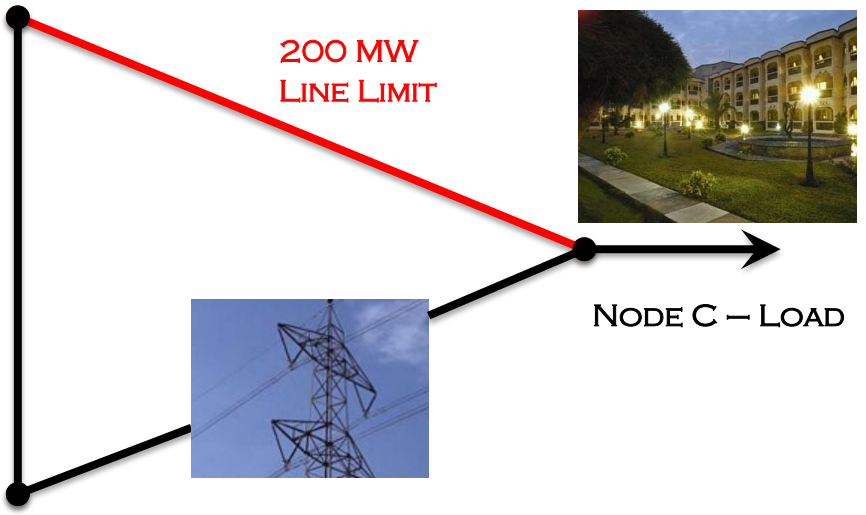
III. There is a single load at Node C.

IV. Under this scenario, VRA is able to contract with the load at C to provide physical power to Node C.
   A. VRA can contract to sell actual delivered MWs with C as the delivery point.

V. As the generation owner and transmission system operator, VRA will decide how much each facility will be used while meeting both the contract requirements and operating reliably.



Node A – Generator (G1)



*For simplicity, assume the transmission lines are lossless and of equal length.

Initial Observations from the Simplified Model

I. In this simple example the contract price will reflect the cost to VRA of:
   A. Producing the electricity,
   B. Managing transmission constraints and line losses, and
   C. Providing ancillary services (excluding reactive power), including the provision of capacity.

II. The consumers at C have no real interest in:
   A. How VRA uses it facilities, i.e. the load does not care which generators are running,
   B. How VRA manages transmission constraints, i.e. the load does not care if there is congestion or line losses, or
   C. How or when VRA conducts maintenance on either the transmission or generation facilities,

III. In short, the consumers at C receives and pays for energy at their delivery point and VRA gets paid to provide that energy and make sure the energy is delivered to the appropriate delivery point (in this case Node C).

Using the simplified model to explain what is going on behind the scenes

I. Before it can contract, VRA has to determine the amount of available generation and transmission capacity while recognizing reliability constraints.
   A. Otherwise it may enter into a contract that it cannot fulfill.
      i. Needs to determine just how much delivered energy it can produce and deliver to all points.
   B. Determining capacity for generation is relatively straightforward…but it is a different story for transmission.

II. As we will see in the next two slides there is no single answer to the question of how much transmission capacity is available…rather the answer is – "It depends…"

Using the Simplified Model to Determine Transmission Capacity if Annual Peak Load is 200 MW

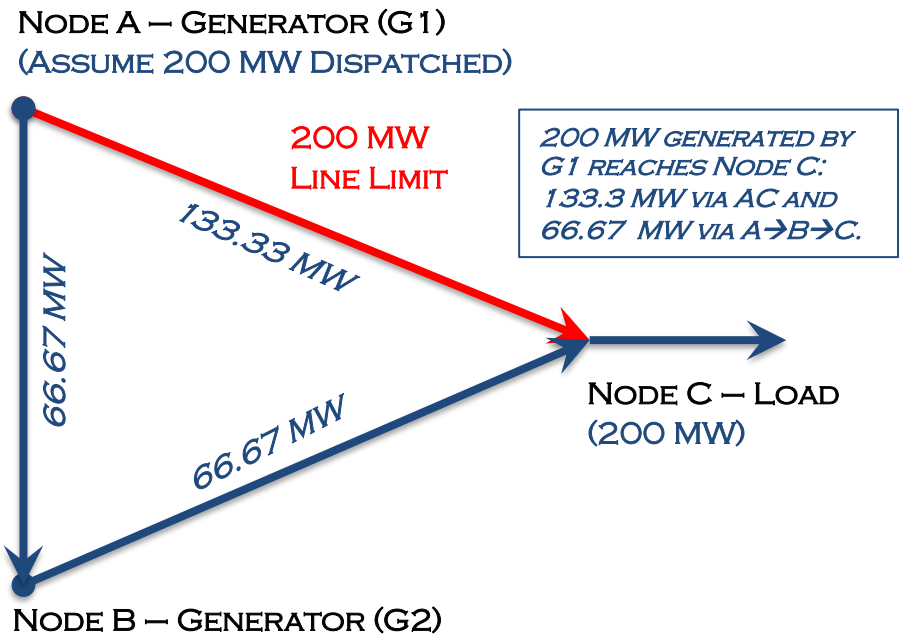
I. Suppose the three node model represents the total system, i.e. there are only two generators and one load.

II. Need to learn (or remember) Kirchoff's 1st Law, i.e. the Law of Circuits:

- A. For every MW produced by G1, 2/3 MW will flow along line AC and 1/3 along lines AB and BC.
- B. For every MW produced by G2, 2/3 MW will flow along BC and 1/3 MW along lines BA and AC.

III. Let's assume the expected annual peak load at C is 200 MW.

- A. In this case either G1 or G2 could produce all 200 MW.
  - i. If G1 produced 200 MW, 133 1/3 MW would flow along line AC and 66 2/3 MW would flow along lines AB and BC.
  - ii. What would it look like if G2 produced the 200 MW?

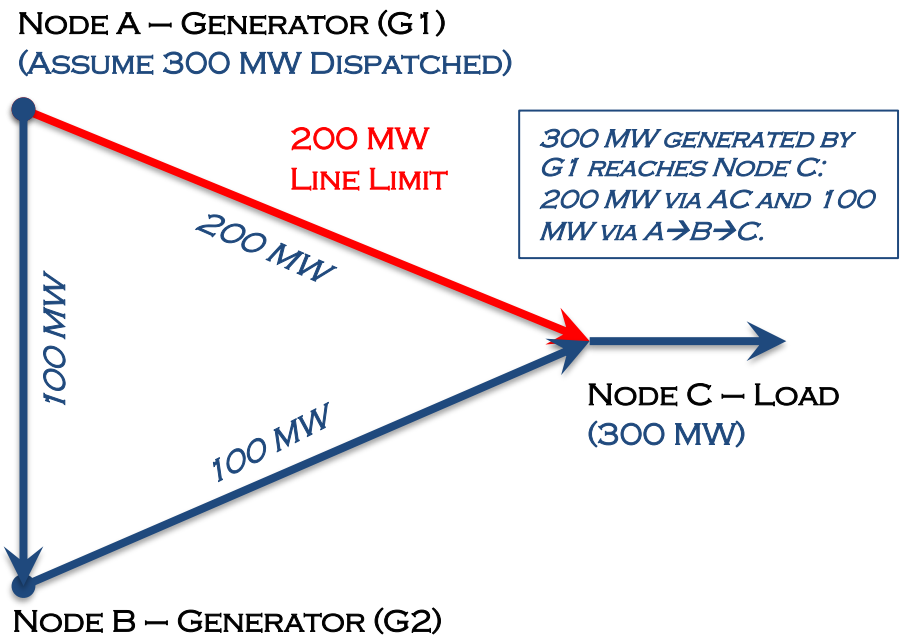


Using the Simplified Model to Determine Transmission Capacity if Annual Peak Load is 300 MW

I. In the previous slide the annual peak load at C was assumed to be 200 MW…and it did not matter whether G1 or G2 or some combination produced the 200 MW.

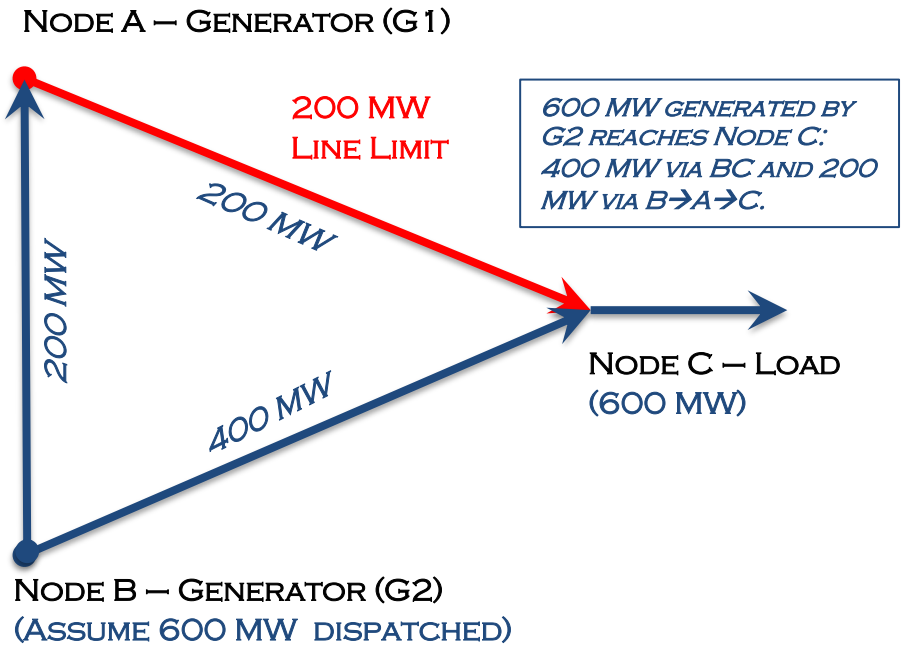
II. Now let's assume the annual peak load at C is 300 MW:

- A. As with the first example, either G1 or G2 can produce all 300 MW.
- B. If G1 produces 300 MW, then 200 MW flows along AC and 100 MW flows along AB and BC.
- C. Notice that when G1 produces 300 MW to meet the load, then the line AC is thermally constrained, i.e. no more energy can flow through AC.
- D. What happens if G2, rather than G1, produces the 300 MW?
  - i. In this case, 200 MW would flow along line BC and 100 MW would flow along lines BA and AC.
  - ii. Line AC would not be thermally constrained.



Using the Simplified Model to Determine Transmission Capacity if Annual Peak Load is 600 MW

I. In the previous slide the annual peak load at C was assumed to be 300 MW…Now let's assume the annual peak load at C is 600 MW:
   A. The key to understanding the solution is to remember that for every 1 MW that G1 produces, 2/3 MW flows along AC which has a thermal constraint of 200 MW.
   B. The only way the simple transmission system can transfer 600 MW is if G2 produces the entire amount.
      i. If G2 produces 600 MW, 400 MW flows along BC, and 200 MW flows along BA and AC.
      ii. Line AC is thermally constrained
   C. Verify that 600 MW is the maximum transfer capability of this transmission system.
      i. Given this transmission system there is no way to produce and transfer more than 600 MW.



Summary - Contracting Under Vertical Integration

I. In the previous slides, VRA as the owner and operator of the generation and transmission assets, needs to determine the capacity not only of the generation facilities but also the transmission transfer capability.

II. Once this capacity has been determined, VRA is free to contract with consumers up to the maximum capacity available (given all reliability constraints).

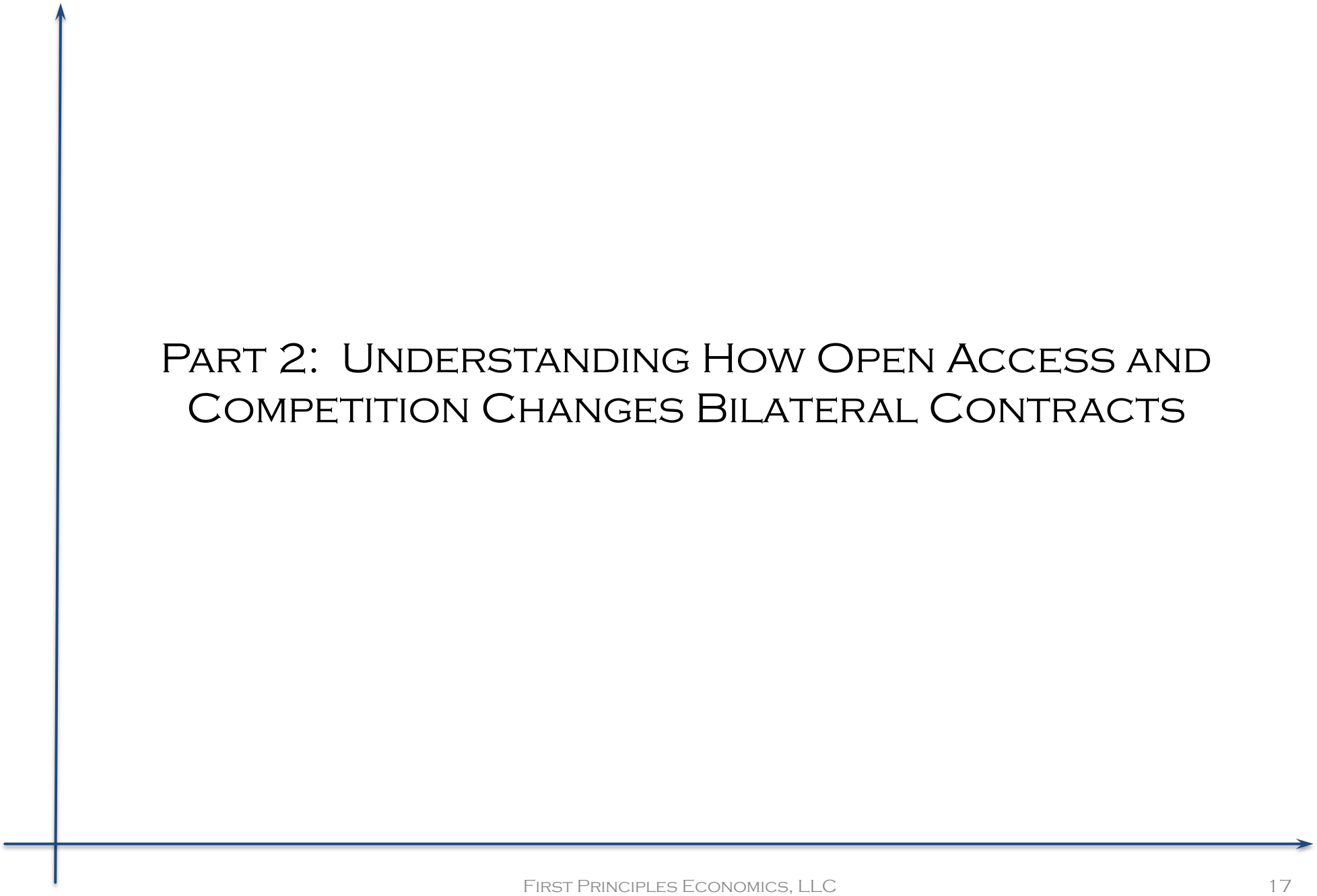
   A. In the example from the past few slides, VRA can enter into bilateral contracts for up to 600 MW of peak demand.

III. The bilateral contract is a "delivered energy" contract – VRA contracts to "deliver" energy to consumers – with Node C being the delivery point.

   A. The key terms are (1) price, (2) quantity, (3) duration, (4) location of the delivery point, (5) credit, and (6) load growth.

IV. Vertical integration allows much of the physical complexity to be invisible, i.e. the complexity is not part of the contract.

   A. This does not mean the complexity does not exist, only that it was internalized within VRA (and non-transparently paid for by the load).



Part 2: Understanding How Open Access and Competition Changes Bilateral Contracts

Competition Requires Non-Discriminatory Open Access to the Transmission Grid

I. In the three node model used in the previous section, no other entity other than VRA was allowed to own/operate generation, i.e. there was no competition in the generation sector.

II. What must take place if we want to allow competition in the generation sector?

- A. Before a potential competitor to VRA will operate, they must be assured that they will have fair and non-discriminatory access to the transmission grid.
- B. Otherwise, they may buy/build a generator and then not be able to sell the power.
- C. The transmission grid must be independent of the generation.
  - i. If the transmission owner/operator is affiliated with any particular generator or subset of generators, then there is the potential for "self-dealing," i.e. there is the potential for the transmission operator to grant preferential access to one generator thereby harming the other generator(s).
- D. In our example, the transmission assets and their operation must be separated from VRA.
  - i. Vertically integrated VRA becomes VRA (generation) and GRIDCo (transmission).

Separating Transmission from Generation Changes *Everything*!

I. What may seem to be a relatively simple change in corporate structure, is in fact significant and leads to a complete change in the contracting structure.
   A. Continuing with the simple model from the previous section, VRA is now a pure generation company and no longer operates the transmission grid.
   B. VRA no longer determines:
      i. The capacity of the transmission system.
      ii. Which generation plants are dispatched.
      iii. How to operate the system reliably, i.e. which plants are used for voltage, frequency, etc.
   C. ...Rather a new entity, GRIDCo, performs these activities.

II. VRA's ability to fulfill "delivered energy" contracts as they did before now depends on how GRIDCo operates the transmission system.
   A. VRA is no longer able to internalize the decisions about how best to fulfill the contract...they cannot make unilateral decisions over generation and transmission
      i. Given the old delivered energy contract, VRA would now have unmanageable risks.

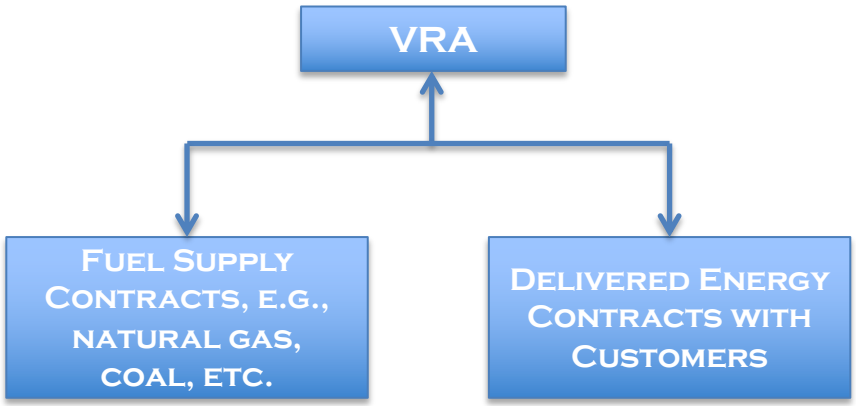
An Evolving Contract Environment…

I. Prior the imposition of Open Access, our simple industry (three lines and nodes, two generators and one load) had a simple contracting environment.

II. VRA as a monopolist had unilateral control over generation and transmission and internalized the complexity of grid operations, i.e. consumers do not "see" the complexity in their contracts with VRA.

III. Reliable operations can be defined and determined unilaterally by VRA.

IV. Since VRA owns/operates the transmission assets they do not need to write a contract with themselves to use the transmission system.



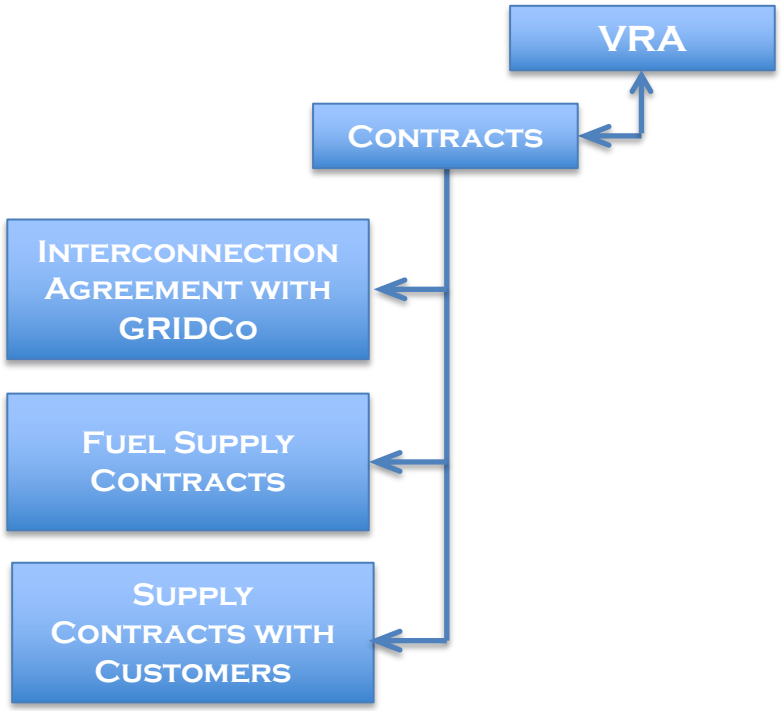
...Becomes Slightly More Complex...

I. When VRA is separated into two companies, the generation business must enter into a contract with the transmission business to define the terms and conditions under which a generator (any generator!) can connect to the transmission system.

II. The terms and conditions of this Interconnection Agreement have the potential to constrain the terms and conditions of other contracts VRA will need to enter into.

III. VRA will continue to have fuel supply contracts.

IV. VRA will continue to have supply contracts with customers.



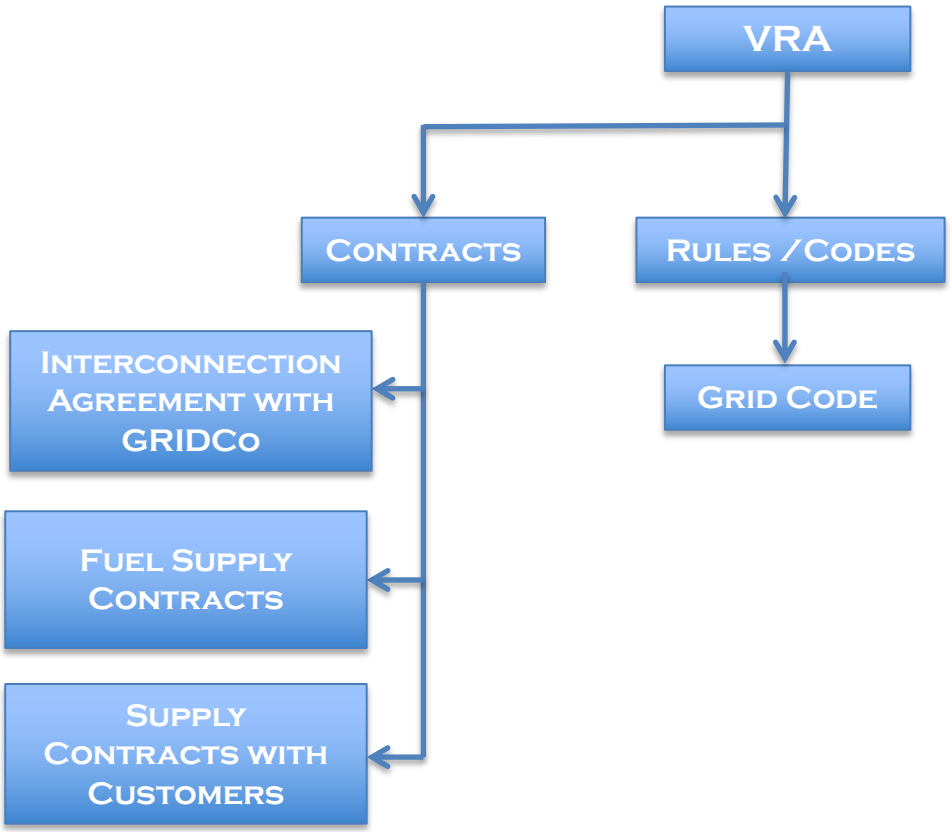
…BUT IT IS ACTUALLY MORE COMPLEX THAN THAT…

I. Furthermore, in order to offer non-discriminatory access, GRIDCo needs to operate according to a set "rulebook."
   A. This rulebook is the Grid Code.

II. The Grid Code defines reliable operation of the transmission system.
   A. The rules contained in the Grid Code represent another set of Terms and Conditions that are no longer unilaterally determined by GENCO.

III. The Grid Code is not synonymous with the Interconnection Agreement.
   A. One deals with physical connection while the other deals with reliable operation.

IV. The Grid Code will constrain the terms and conditions of other contracts entered into by VRA.



The Interconnection Agreement and the Grid Code

I. Competition and Open Access leads to the creation of GRIDCo:
   A. The creation of GRIDCo necessitates two legal/contractual agreements:
      A. An Interconnection agreement between GRIDCo and the owners/operators of grid connected load and generation assets.
         i. Asset-to-asset relationship.
      B. The rules by which GRIDCo will operate the transmission system.
         i. Transparent, equitable and non-discriminatory set of rules regarding reliable grid operation.
            - Usually accompanied by operation manuals.

II. The situation in Ghana is not unique:
   A. New Zealand – Transpower
   B. Queensland – Powerlink
   C. South Australia – ElectraNet
   D. UK – National Grid....

The Interconnection Agreement

I. What is an Interconnection Agreement?
   A. GRIDCo needs to establish a legal/commercial/operational relationship with grid-connected assets.
      i. Ensures consistency between and among assets.
      ii. Essential for reliability. Example: require all generating facilities be capable of withstanding a decline in frequency of 5% (i.e. down to 47.5 Hz
      iii. Enforcement of metering standards and requirements.
II. What are required elements of an Interconnection Agreement?
   A. No set standard.
   B. Detailed description of the physical assets being connected.
      i. The equipment and the design specifications, drawings, and documentation as-built.
      ii. Additional information, including but not limited to:
         - System protection facilities, communication requirements, metering requirements, grounding requirements, transmission line and substation connection configurations, unit stability requirements, equipment ratings, short circuit requirements, synchronizing requirements, generation and operation control requirements, data provisions, energization inspection and testing requirements, etc.
      iii. Outage coordination and interruptions: coordination, schedules, and restoration procedures.
      iv. Legal ownership and financial responsibility.
      v. Performance and Maintenance obligations.

The purpose behind the Grid Code

I. Competition and Open Access leads to the creation of GRIDCo:

A. Creating "GRIDCo" necessarily requires the establishment of a "Grid Code."

i. Why? Because GRIDCo* as the system operator and not an asset owner is a service provider and not a principal in the industry…it does not own assets. In this regard it is similar to an air traffic controller at an airport. As such it needs to operate to a set of known and transparent rules to ensure non-discriminatory treatment of the connected assets. Otherwise, there will never be effective competition.

ii. Thus…"*The National Electricity Grid Code of Ghana…establishes the requirements, procedures, practices and standards that govern the development, operation, maintenance and use of the high voltage transmission system in Ghana.*

…The purpose is to ensure that the NITS provides fair, transparent, non-discriminatory, safe, reliable, secure and cost efficient delivery of electrical energy."

ii. The inclusion of "cost efficient" is problematic.

B. Ignoring for the moment the objective of cost efficiency, the purpose of the Grid Code is to serve as a set of rules for GRIDCo.

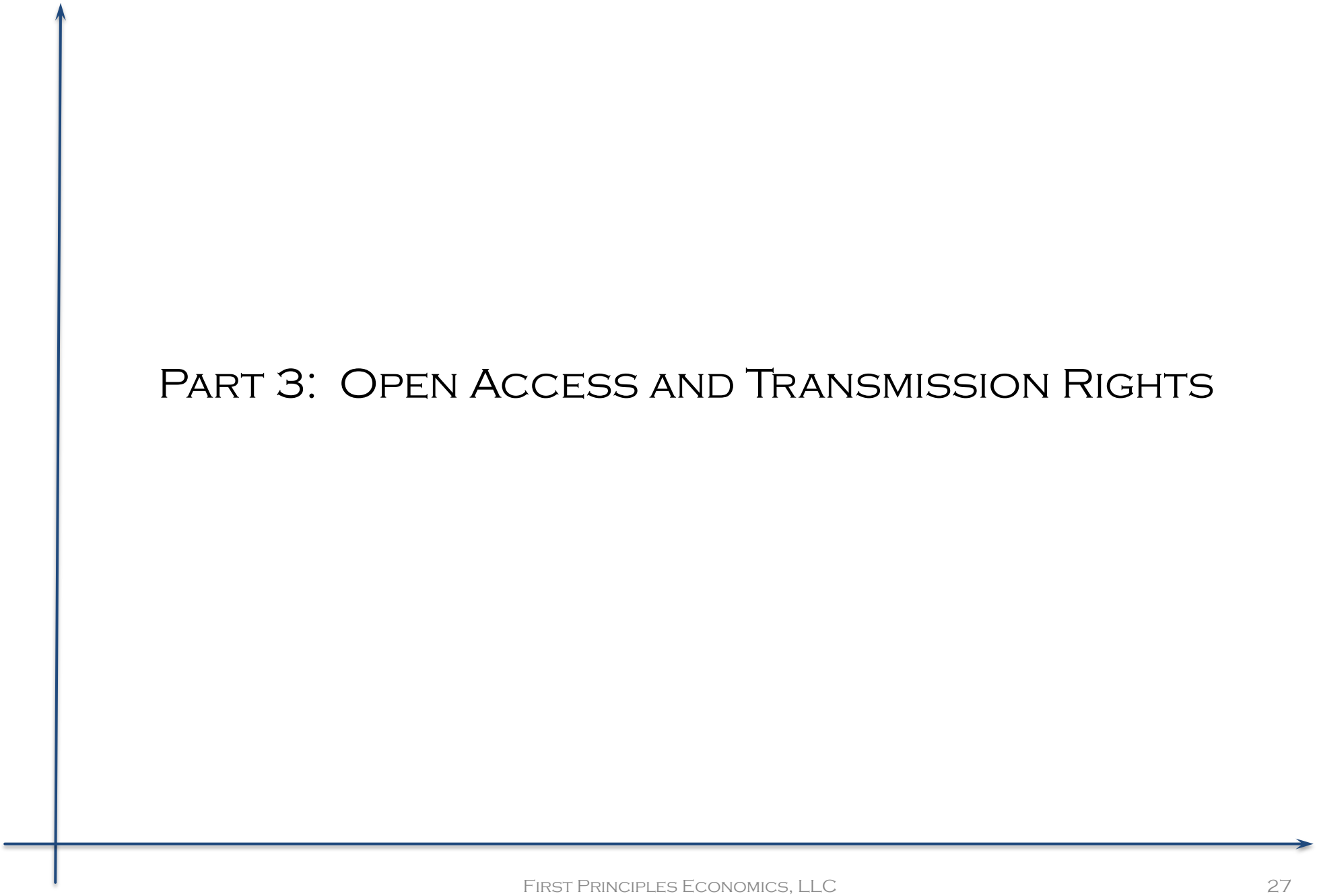
i. The rules are (or should be) specifically focused on maintaining reliability.

*GRIDCo as asset owner and grid operator is an interim step. Ultimately the ETU will be separated from GRIDCo.

Basic Elements of the Grid Code

I. As it currently stands the Grid Code is a broad document.
   A. It is more typical for the rules pertaining to physical reliability to be separate from economic considerations.
   B. This is mirrored in the regulatory institutions as well…there is a "physical regulator" and a "market or economic regulator"

II. The separation between "physical" and "financial" stems from the original model of vertical integration.
   A. Financial or economic regulation relates to cost recovery, i.e. regulated prices, rates of return, etc, over a portfolio of assets. The concern is the economic situation of the vertical integrated entity.
   B. Thus is is appropriate to create "reliability" rules and regulations that are distinct from economic rules and regulation.
   C. This dichotomy changes under disaggregation of the generation and transmission assets and competition.
      i. In New Zealand, originally the Market and Gird Security Rules were separate entities…they have since been linked.
      ii. In the US, NERC (North American Electricity Reliability Corporation) and FERC (Federal Regulatory Energy Commission) were responsible for reliability and economic regulation respectively until the Energy Policy Act, 2005, which gave FERC the authority to impose mandatory reliability standards on the bulk transmission system.



Part 3: Open Access and Transmission Rights

Transmission "Rights"

I. In addition to causing a need to separate GRIDCo from VRA which then necessitates the creation of both an Interconnection Agreement and a Grid Code, open access requires that "transmission rights" be defined and determined.

II. Remember, that when VRA owned and operated both the generation facilities and the transmission grid, no other entity had access to the transmission system. There was no need to define and determine a transmission right because no generator other than VRA could access the grid.

A. A Transmission Right is a "right" to use the transmission system.

i. What constitutes "use" of the transmission system?

- Access to transmission capacity.
- Access to the dispatch process.

B. Let's use an airport as an analogy.

i. If an airline company wants to use the airport they need to have "landing strip capacity", i.e. they need to own, rent, or lease, some amount of the physical capacity of the landing strip.

ii. They also need the air traffic controller to allow them to take off and land.

✧ *A user of the electricity grid has the same requirements!*

Transmission Rights – Some Important Considerations

I. In defining a transmission right, there are some fundamental issues or characteristics that need to be resolved:

A. What "rights" and "obligations" are attached to a transmission right?

i. Will either a buyer or seller be required to have a transmission right if they produce or consume power…what requirements must they meet?

B. Will there be different levels of rights?

i. Will some transmission rights have a higher level of service, e.g. will they receive preferential treatment?

- For example, suppose a constraint arises and not all capacity is available and some users are not able to use all of their transmission rights, is there some "ranking' as to who gets cut or is it on a pro rata basis?

C. Who will be responsible for determining the quantity of transmission rights that are available?

i. Will it be the transmission asset owner (i.e. GRIDCo), or

ii. Will it be the system operator (i.e. ETU)?

D. What methodology will be used to determine the quantity of transmission rights?

i. Average or peak? How will outages be handled?

Transmission Rights – Some Additional Important Considerations

E. What obligations, i.e. responsibilities and liabilities, are placed on the "creator" of the transmission rights?
   i. What if they issue too many? Too few?

F. Will there be regulatory oversight?
   i. Will transmission customers be able to participate?

G. How will the transmission rights be priced?

H. Who receives the revenues?

I. How will they be allocated?
   i. Will they allocated to participants, auctioned…or is there a different mechanism?

J. What will be the term/duration of a transmission right?
   i. If there is going to be more than one period, how will transmission capacity be allocated across the different periods?
   - For example, suppose we decide to create and offer a 1 year transmission right and a 3 year transmission right. How much transmission capacity do we make available for each potential category?

K. Does an existing holder of a transmission right receive preferential rights for acquiring them in subsequent periods?
   i. That is, are there "rollover rights?"

Addressing the Issues Surrounding Transmission Rights…

…is not an option. If competition is going to occur, then these, and many additional related, questions will have to be answered.

I. Not addressing these issues will result in inefficiency, poor investment choices, and ultimately the failure of open access.

II. How these questions are addressed provide the operational and commercial platform for the industry.

III. Returning to the airport example: how would the airline or a customer purchase a ticket if they did not know when or how they could take off or land?

A. What language would the airline company use?

1. *We will sell you a seat on the plane but we cannot guarantee there will be a plane available. Nor can we guarantee when the plane will be allowed to take off. Hence we cannot guarantee when, or even if, you will arrive at the destination you purchased the ticket for!*

IV. The fundamental issue was not created by competition or open access…but it was previously all dealt with internally by VRA as a vertically integrated monopolist…and now that "complexity" is transparent and must be dealt with explicitly and formally rather than implicitly and informally by VRA.

Two Methods to Handle Transmission Rights

Defining and determining transmission rights is a necessary step in implementing competition. As a result, this issue has been dealt with in other areas.

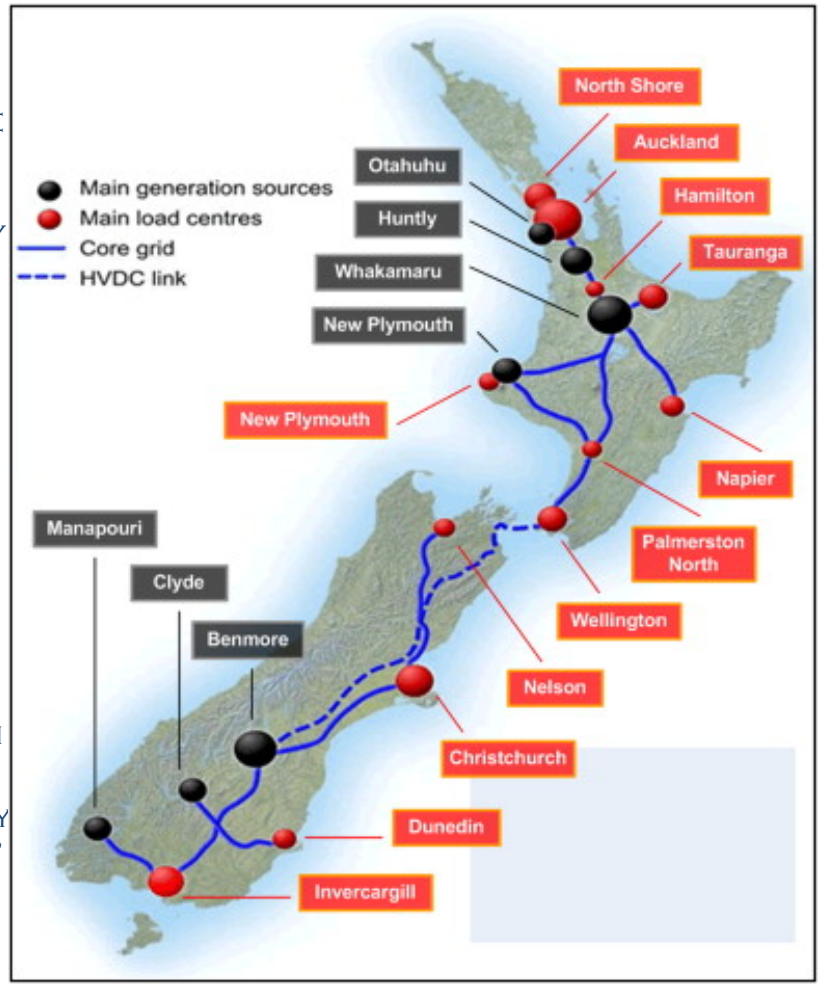
I. Two distinct methodologies have been developed.
   A. The "physical rights model" whereby a transmission right has a physical interpretation.
   B. The "financial rights model" whereby a transmission right has no physical interpretation, rather it is purely a financial right to revenue streams (positive or negative) that arise from using the transmission system.

II. While these are two very distinct approaches they are best thought of as evolutionary.
   A. Physical transmission rights are best thought of as a "bridge" or intermediate step.
      i. A mechanism to implement open access without implementing centralized dispatch, i.e. an electricity spot market.
   B. Financial transmission rights are consistent with the final step in creating an electricity market and they replace physical rights.

New Zealand Case Study – Before Open Access

New Zealand represents an interesting case study. Structurally, the electricity sector in New Zealand in 1993 was somewhat similar to Ghana – at least before Sunon-Asogli started producing.

- Two islands connected by a DC tie. Majority of load on the North Island. Majority of generation capacity on the South Island. North Island generation was predominantly thermal and South Island was hydro (70% of total capacity was hydro). Dual peaking system – North Island in the summer, South Island in the winter
- A single generator - Electricity Corporation of New Zealand (ECNZ) that was a State Owned Enterprise (SOE)
- The high voltage transmission assets and grid operation had been separated into Transpower, another SOE.
- There were a number of vertically integrated local distribution and retail companies.
- There were no explicit or defined "transmission rights.
- Contracts were in the form of an annual "hedge" whereby ECNZ and a customer would agree on a price and quantity.
  - There were two possible delivery points – 1 in the North Island (Haywards) and 1 in the South Island (Benmore).
  - An hourly wholesale "spot" price was calculated weekly for both delivery points...single "Island" Marginal Cost" based on the cost of the "marginal" generator. Prices at the two points deviated whenever the DC tie was constrained (which was almost always)...
  - The hedges settled against this price...hedge was a swap.



New Zealand Case Study – With Open Access

In 1995 the New Zealand government announced that ECNZ would be separated into two competing companies – ECNZ and Contact Energy. Open access to the transmission system had to be implemented.

- The industry developed the (market) rules for non-discriminatory centralized dispatch.
  - Market was simply a derivative of the dispatch process.
- The rules specified that the dispatch for any interval would be least-cost based on the offers made by generators.
- Access to the transmission system for individual generation facilities was based on the as offered price(s) of each individual unit.
  - Non-discriminatory access since the rules apply to all generation and each unit is free to offer at whatever price they want.
- Dispatch was accomplished through centralized security constrained economic dispatch (SCED).
- Prices were created every 15 minutes for approximately 240 different electrical locations (nodes) around the country.
  - Transmission constraints, reserves and losses all caused prices to deviate…no single Island price.
  - Physical dispatch was mandatory and everybody either received or paid the 15 minute prices.
- Bilateral contracts were still written using Haywards and Benmore as the delivery points and were still in the form of hedge contracts that settled against the 15 minute prices.
- Counterparties had to factor in their exposure to transmission constraints in their bilateral contracts, e.g., the delivery point for the bilateral contract was at Haywards but the physical load might be at Hamilton…if there were transmission constraints then prices at Hamilton to be different than the Haywards price paid by customer.

New Zealand – Case Study Conclusions

Remember there are two aspects to the "issue" of transmission rights: (1) defining and acquiring the capacity on the transmission system and (2) ensuring the dispatch is non-discriminatory.

New Zealand solved these two problems *simultaneously* by:

- Implementing *security constrained economic dispatch* based on generator offers. This solved the question of ensuring non-discriminatory access to the "air traffic controller" – every generating unit was treated the same.
- The issue of allocating transmission capacity was dealt with implicitly. When transmission capacity on the system or a line was scarce because of high demand or transmission constraints, prices across the system deviated and customers wore the financial risk.
- *Note: In 2012, New Zealand explicitly dealt with the issue of transmission rights by implementing financial transmission rights.*

New Zealand – Case Study Conclusions (Continued)

With respect to the current situation in Ghana, there are two relevant aspects of the New Zealand example.

1. New Zealand went directly from a monopoly vertically integrated wholesale sector to centralized security constrained economic dispatch (SCED) performed by a market operator. In this model, the dispatch process creates a price at every node – generators are paid the price at their node, and load pays the price at their node. Also in this structure, bilateral contracts take the form of a swap or contract for difference (CFD) and settle against the real time price…these contracts were similar to the previous ECNZ annual hedge contracts that had been in effect prior to open access, so participants were familiar with them.

2. In effect, New Zealand did create a type of financial transmission right…everybody was given the right to access the grid based on their offers and willingness to be exposed to the financial effects of constraints.
   - Consider a highway that allows anybody to drive on the road. In this case the driver does not receive any rights beyond the right to use the highway. The driver must internalize all the costs associated with road maintenance (outages), traffic (transmission constraints), etc.

United States Case Study – Background

The United States provides a very different example with respect to implementing competition.

- Vertical integration in the US was across both the wholesale and retail sectors.
- Unlike New Zealand and Ghana where wholesale activities (generation and transmission) were carried out by a government-owned monopoly who supplied local monopolies, in the US all activities from generation to transmission and distribution, and finally to retailing were all carried out by a single vertically integrated monopoly called an Investor Owned Utility (IOU) who was granted a "franchise" or geographical territory by the government.
- Monopoly IOUs face regulation by the Federal Government (to the extent they engage in interstate commerce) and State government(s) where they operate.
- Ownership differences between New Zealand/Ghana and the US are important with respect to industry reform. To the extent that reform causes wealth transfers this affects private shareholders in the US. (An important consideration as industry evolves and the rules change).
- Allowing competition in the electricity sector was started after competition was allowed in the natural gas market. The gas market experience had a tremendous influence on how open access was implemented in the electricity sector in the US (the concept of physical transmission rights originates from the natural gas market).
- The success of the gas market was based on separating transmission pipelines from gas production and the requiring them to offer transport services only.

United States Case Study – Implementing Open Access

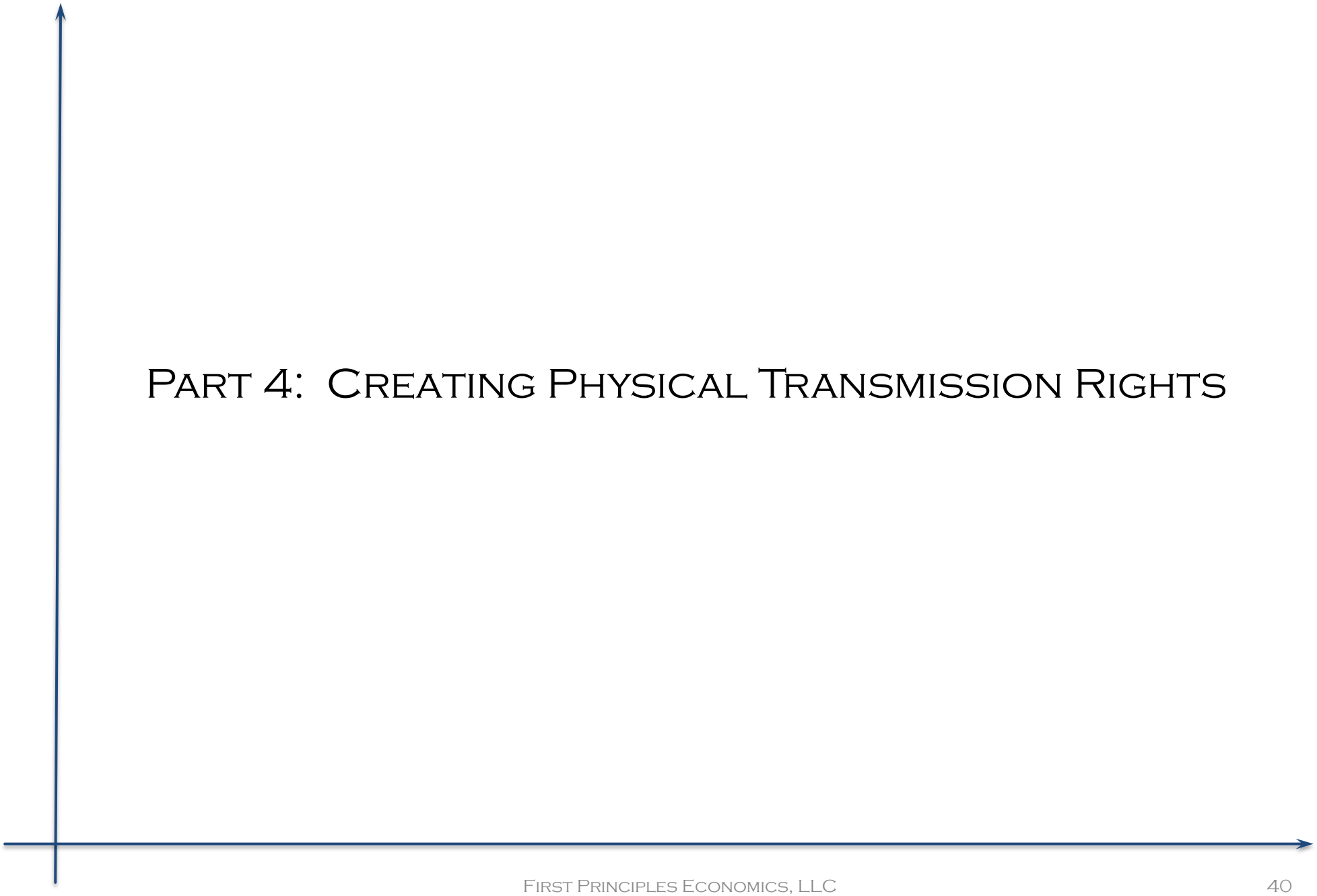
Implementing competition and open access in natural gas was a long process but after finally getting it right, a similar policy objective for electricity was pursued and gained momentum with Federal Energy Regulator Commission Orders 888 (1996) and 2000 (2000).

- Policy directives initially pursued an objective of *not* explicitly creating electricity markets. Rather the focus on the policy and regulatory decisions was on removing the institutional obstacles, e.g. functional if not actual separation of transmission from generation.
- The belief was that if these institutional structures were eliminated then an electricity market would develop just like it had in the natural gas industry.
- After functionally separating transmission, the next step was to define what constituted "transmission service."
  - Define the capacity of the transmission network and then sell that capacity to those who want to use it.
  - Just like what had been done in the natural gas transport sector.
  - Transmission products were developed based on "firm service", "interruptible service", "network service"…each of these "services" had a set of attributes.
  - The assumption was that once these services were defined then a market would evolve.
  - Just like in the gas industry, if you wanted to physically produce/consume electricity you needed to acquire the associated service.
    - Led to new terminology, operations, interactions, contracting, etc.
      - » All transactions had to be physically scheduled…physical source/sink pairs…OASIS (Open Access Same Time Information System)…NERC tagging.
      - » Commercial contracting reflected the underlying structure.

United States Case Study – Comments on Initial Attempts

Initial attempts to implement open access in the US were not very successful. That is, they had limited success in improving economic efficiency and creating a competitive industry.

- The primary problem was related to the reliance on "physical rights" for transmission.
- In order for the physical rights model to work, the capacity has to be defined and allocated in advance of real time. Thus participants can acquire the rights that they need and then schedule their anticipated power flows.
- In simple terms the fundamental problem is that capacity on the transmission system – as any power systems engineer will tell you – is dynamic and can only be accurately determined in real time.
- Thus there was a disconnect between the rights that had been allocated and the actual capacity that was available in real time.
- Furthermore, the "market" cannot respond in the time frames necessary in real time.
  - The rights could not be exchanged in the market quickly enough to match the needs of real time dispatch.
  - *So, what must be done to bridge the gap?*



Part 4: Creating Physical Transmission Rights

The US Example - Defining Physical Transmission Rights – Suppose Load Is 300 MW

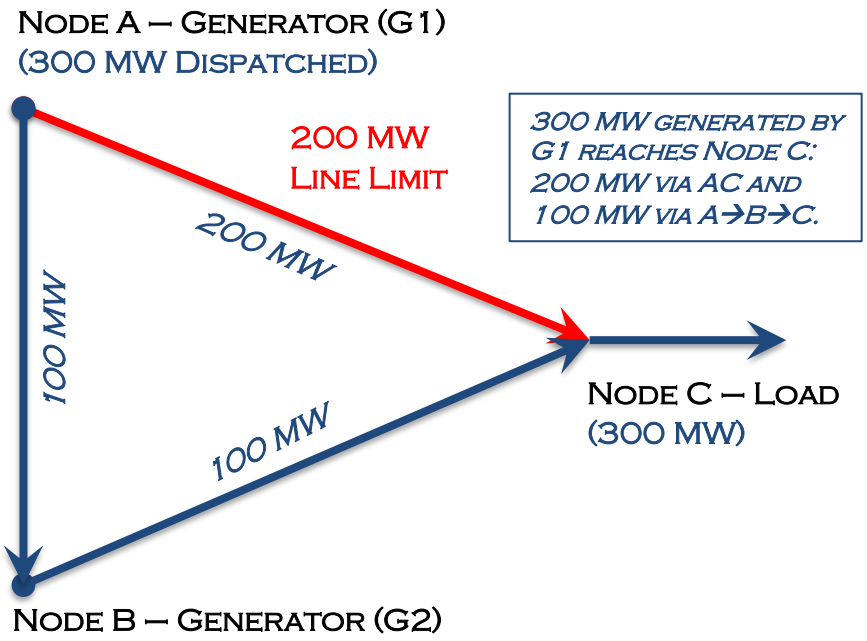
I. The US Model relied on allocating transmission capacity through the creation of physical rights…how is that done?

II. We can use the 3 node model to demonstrate the difficulty in determining transmission capacity.

III. We have already seen that if load at Node C is 300 MW then either G1 or G2 can supply the entire demand.

IV. But, If G1 produces 300 MW then there is no additional capacity on the system. Whereas if G2 produces the 300 MW then there is 300 more MW of capacity, i.e. a total of 600 MW.

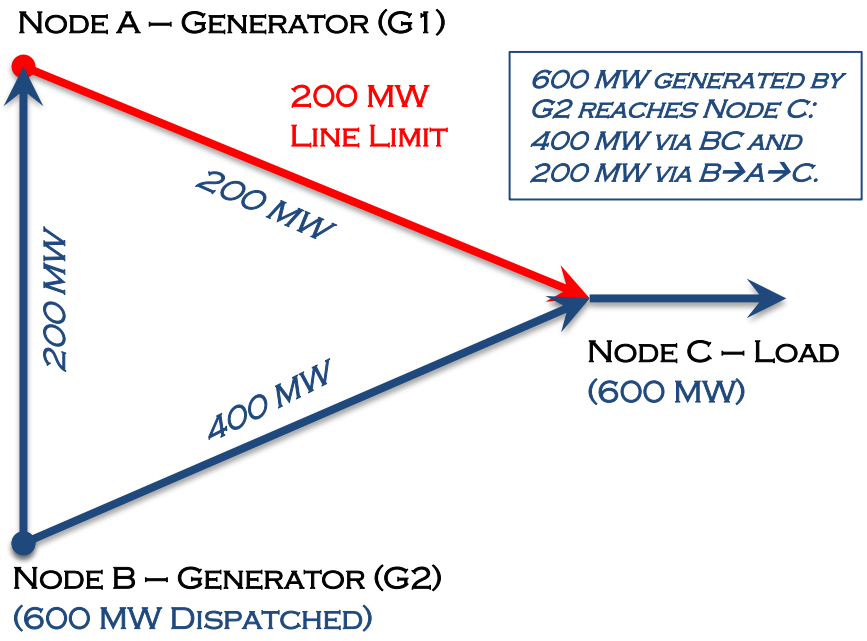
V. This example highlights the central issue of non-discriminatory open access based on physical rights…deciding how many rights to allocate.



Defining Physical Transmission Rights – Now Suppose Load Is 600 MW

I. IF, load at Node C is 600 MW:
   A. It is not possible for G1 to produce 600 MWs. If they did 400 MW would flow along AC.
   B. The only possible solution is for G2 to produce all 600 MWs.
   C. The maximum capacity of this transmission system is 600 MW.

II. How much physical capacity should be defined?
   A. 300 MW, 600 MW…or somewhere in between?



Pre-defining The Capacity Of The Transmission System Is "Difficult"

I. Why is the understanding of this issue important?
   A. Many market design processes assume the "market" can be largely separated from the details of electricity…"keep it simple"…"we don't need all that complexity."
   B. This assumption requires that the amount of transmission capacity be determined in advance and then "physical rights" can be established for the capacity.
   C. These "rights" are then sold or allocated to market participants.
   D. In order to produce/consume physical power, you must have the "right" to transport it from the source to the sink.

II. The previous examples illustrate the difficulty in pre-defining physical property rights on an interconnected grid.
   A. Neither generator can have physical capacity rights over line AC without knowledge of what the other is doing – as well as the level of load – who makes the decisions?

Defining Physical Transmission Rights – What is the real problem?

In order to have true non-discriminatory open access every generator must have an equal opportunity to sell their power…***and the system must be operated reliably!***

I. Using the results from the previous examples, suppose we issue 300 MWs of physical transmission capacity rights.

II. These transmission rights would be necessary in order for a generator to run. That is, a generator must have the transmission rights for the power they are producing.

- A. In order for a generator to run, they must use transmission rights to schedule power from their generation facility (source) to the load (sink).
- B. Now assume that for whatever reason, G1 ends up with all the rights.
- C. On any given day, G1 uses their physical transmission rights to schedule power from their plant at Node A to load at Node C.
- D. As Long as the load is ≤ 300 MW everything is fine. But what happens if load is more than 300 MW?
  - i. With only 300 MW of physical transmission rights available, no additional generation can be scheduled…nobody would have the "right" to schedule.
  - ii. If the dispatcher forced somebody to generate…they would simultaneously violate G1's rights. As was shown, if G1 produces 300 MW, there is no way for G2 to produce anything. The only thing the dispatcher can do in this situation is to mandate that G1 reduce their output and allow G2 to produce, and this would violate G1's transmission rights.

United States Case Study – Next Steps in Implementing Open Access

While the physical rights "model" was able to achieve some of the goals of open access, the inefficiencies were too great relative to the alternative (i.e. the financial rights model). As a result much of the electricity in the US is transacted through a financial rights model similar to that implemented initially in New Zealand.

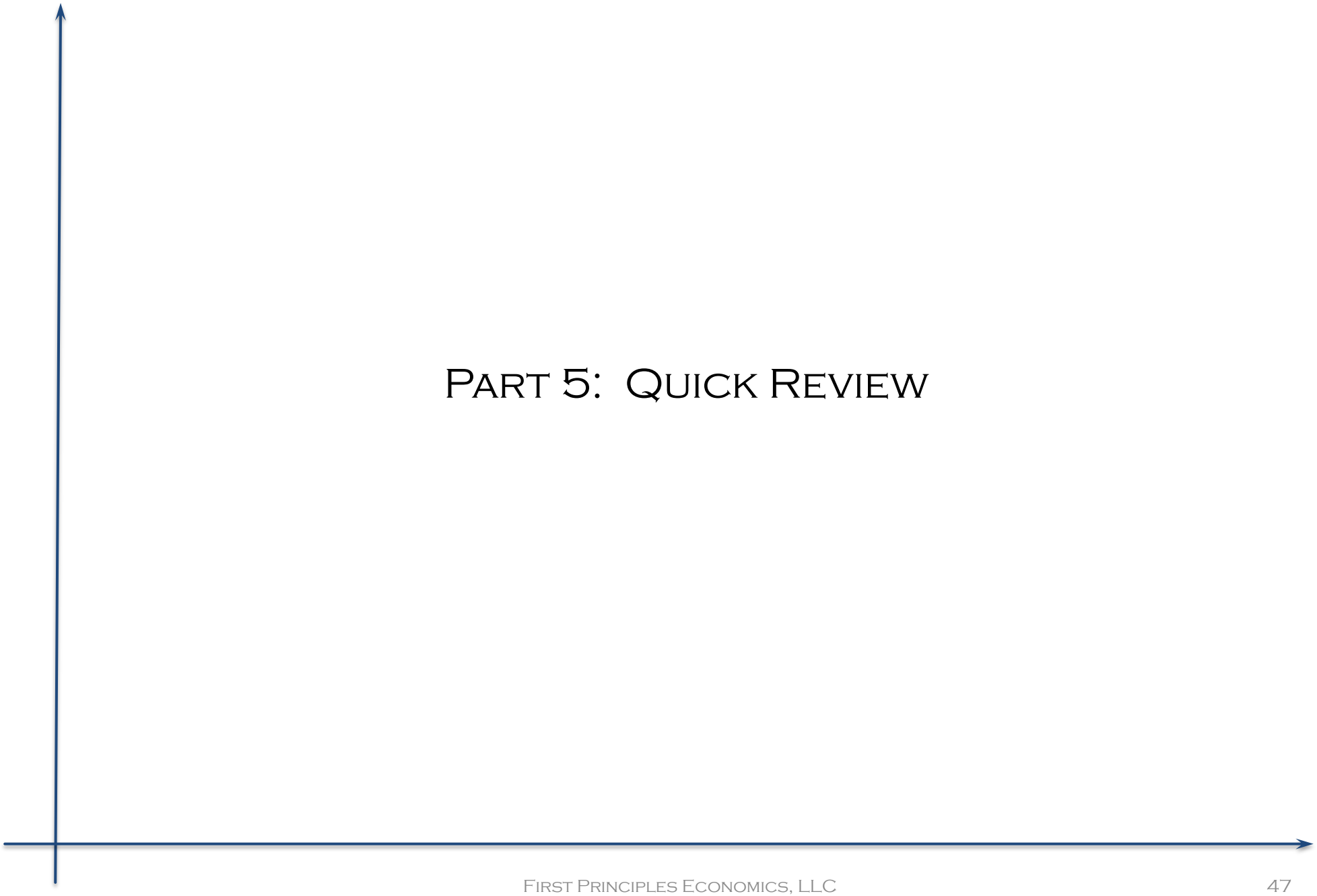
- 7 organized markets based on centralized security constrained economic dispatch using financial transmission rights; ISO* New England, New York ISO, PJM, Midwest ISO, Southwest Power Pool, Electricity Reliability Council of Texas, and the California ISO.
- Active discussion is taking place regarding implementing a form of centralized dispatch in the western states in order to better (i.e. more efficiently) handle the increased amount of wind generation.
- The "evolution" from vertical integration to physical rights and then to financial rights is neither necessary or beneficial.
  - Better to think of the physical rights period as a costly detour.
- Perhaps the most important characteristic of implementing open access in the US, relative to other countries like New Zealand, has been the different ownership structure in the industry, i.e. vertically integrated investor owned utilities as compared to vertically integrated government-owned utilities.

*An ISO is an Independent (Transmission) System Operator

Transmission Rights - Summary

I. The issues are both subtle and complex
   A. Defining the transfer capability of the transmission system is not an "incorrect" exercise…every power system operator/planner does this.
   B. The question is not whether it is right or wrong to calculate the transfer capability but rather how is that information going to be used by (1) the system dispatcher and (2) the dispatch rules.
      i. Remember that any estimate of the transfer capability is just that – an estimate. And it is calculated by making assumptions.
      ii. But in real time…there is only actual generation/load and the actual topology of the grid.
      iii. To the extent the "assumptions" made in determining the transfer capability accurately reflect the reality of what is actually happening, then using the transfer capability as the foundation for the dispatch process is appropriate.
      iv. If the assumptions do not accurately reflect the reality…then there will be problems.
      v. Who makes up the difference (and who pays for it) between what was assumed would happen and what actually does happen?
   C. In most areas, the physical concept of total transfer capability (TTC) has not proven to be an efficient foundation for non-discriminatory open access.
      i. It is a useful tool for transmission planning and reliability analysis but not for real time dispatch.

II. As more competitive generation is developed in Ghana, the issue of transmission rights and non-discriminatory access to dispatch will have to be addressed more precisely.



Part 5: Quick Review

Competition...Open Access...Contracts

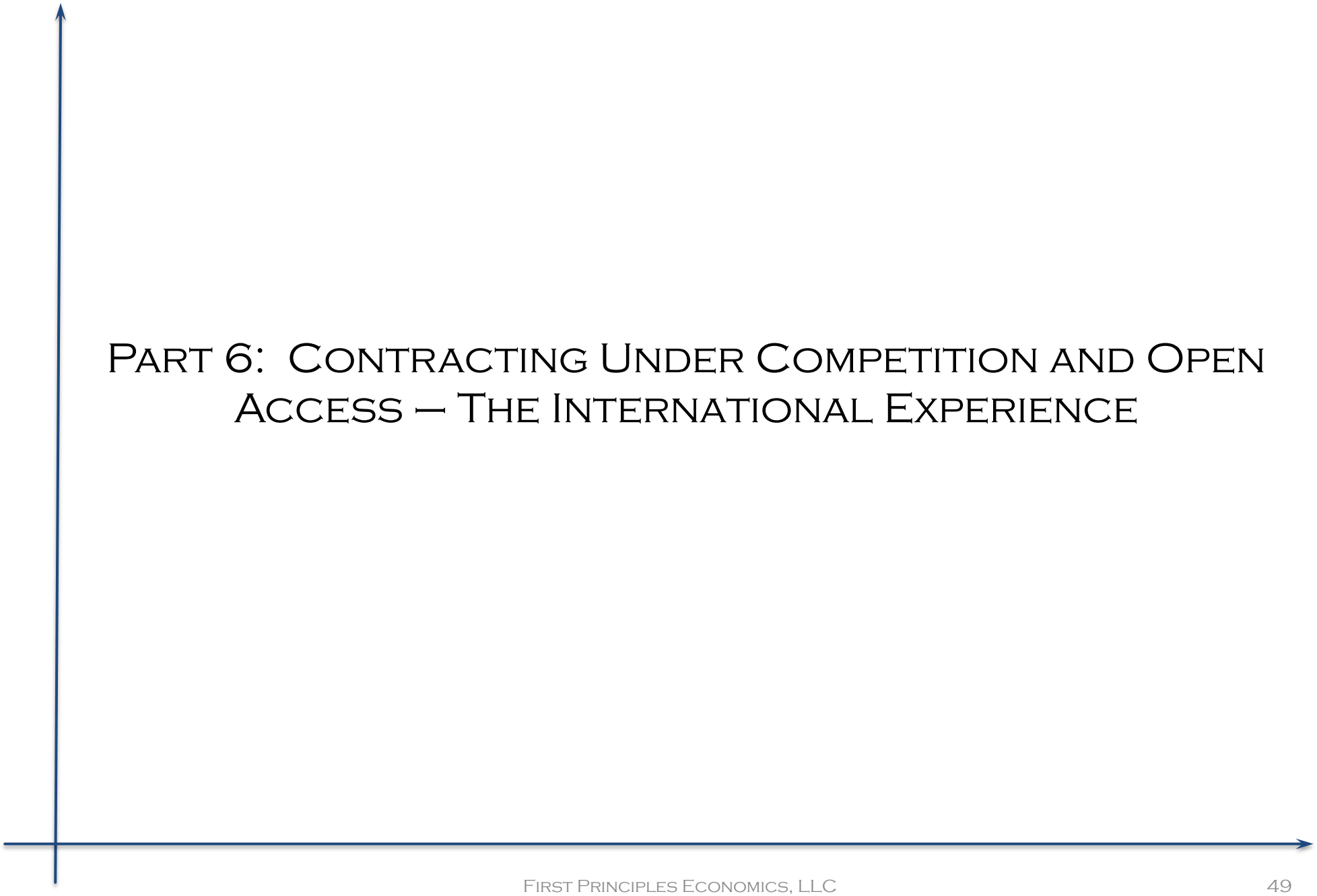
I. When generation and transmission are combined into a vertically integrated monopolist that entity internalizes all of the decisions regarding production, transmission and reliable operation.

II. The commercial contracting structure necessarily reflects that a single entity has the unilateral ability to manage all aspects of supply and transmission.

III. However, once competition is allowed, then the transmission system and its operation must be separated from generation.

IV. The result is that generators no longer have the ability to ensure physical delivery

V. This necessitates that a new contracting structure be developed.



Part 6: Contracting Under Competition and Open Access – The International Experience

Introductory Comments on Contracting

I. We have discussed the basic foundation of contracting when VRA was a vertically integrated monopoly generator and transmission, i.e. that VRA had the structural ability to make unilateral and simultaneous decisions regarding how the transmission system and generation fleet would be used.

II. We have also discussed why implementing competition and open access has completely changed how VRA "interacts" with the transmission system. In particular, VRA no longer makes decisions about how the transmission system will be used.

III. These changes necessarily mean that VRA can no longer unilaterally provide the same price/service they provided prior to the implementation of open access.

IV. As a result VRA must revise the terms and conditions of their Power Supply Purchase Agreements with their customers.

Bilateral Contracts and the Problem of "Overs and Unders" – the Deviations from Contracted Amounts

I. Bilateral contracts (in all their potential forms) are the primary commercial mechanism for exchanging power – regardless of whether competition in the generation sector is allowed.

II. However, competition changes the nature of the contractual relationship.

A. It is a fact that consumers will not use the precise quantity of power they have contracted for, e.g., a customer who has a contract for 25 MW may, on average, use 25 MW, but their load will deviate above and below that amount. This raises two important issues.

i. GRIDCo cannot turn off individual customers when their demand exceeds what they have contracted for…similarly GRIDCo cannot force a customer to consume what they have contracted for.

ii. In the first case the customers is consuming "over" their bilateral amount…in the second they are consuming "under" their contracted amount.

B. In the past VRA – as the monopoly generator – would and could absorb these volume changes unilaterally…they can no longer do so.

C. With competitive generation on the system, there must be a coordinated response.

GRIDCo Coordinates the "Overs and Unders"

I. Suppose, that in real time, a VRA customer uses 5 MW more than the amount they contracted for and was scheduled day ahead…
   A. Which generator provides the extra 5 MW…is it VRA or Sunon-Asogli?
   B. Who decides which generation facility will be used to provide the extra 5 MW?

II. Alternatively, suppose one of VRA's customers uses 5 MW less than the amount they contracted for and was scheduled day ahead…
   A. Which generator gets ramped down the 5 MW…is it VRA or Sunon-Asogli?
   B. Who decides which generation facility will be ramped down?

III. What are the financial consequences of either producing more or ramping down?
   A. How are the these "overs and unders" priced and settled?
   B. Now and in the future? The complexity with two competitive generators is very different than it is with more than two.
      i. If done bilaterally, then we would need identical bilateral contracts between every generator.

Contracting Under Open Access – International Experiences

I. Commercial contracting for electricity must reflect/mirror the rules under which competition and open access have been implemented.
   A. This is a current issue for the Ghanaian electricity market…the rules and procedures have not been determined/finalized.
      i. Interconnection agreement between grid users and the transmission system.
      ii. The grid operating procedures, specifically the allocation of transmission rights.

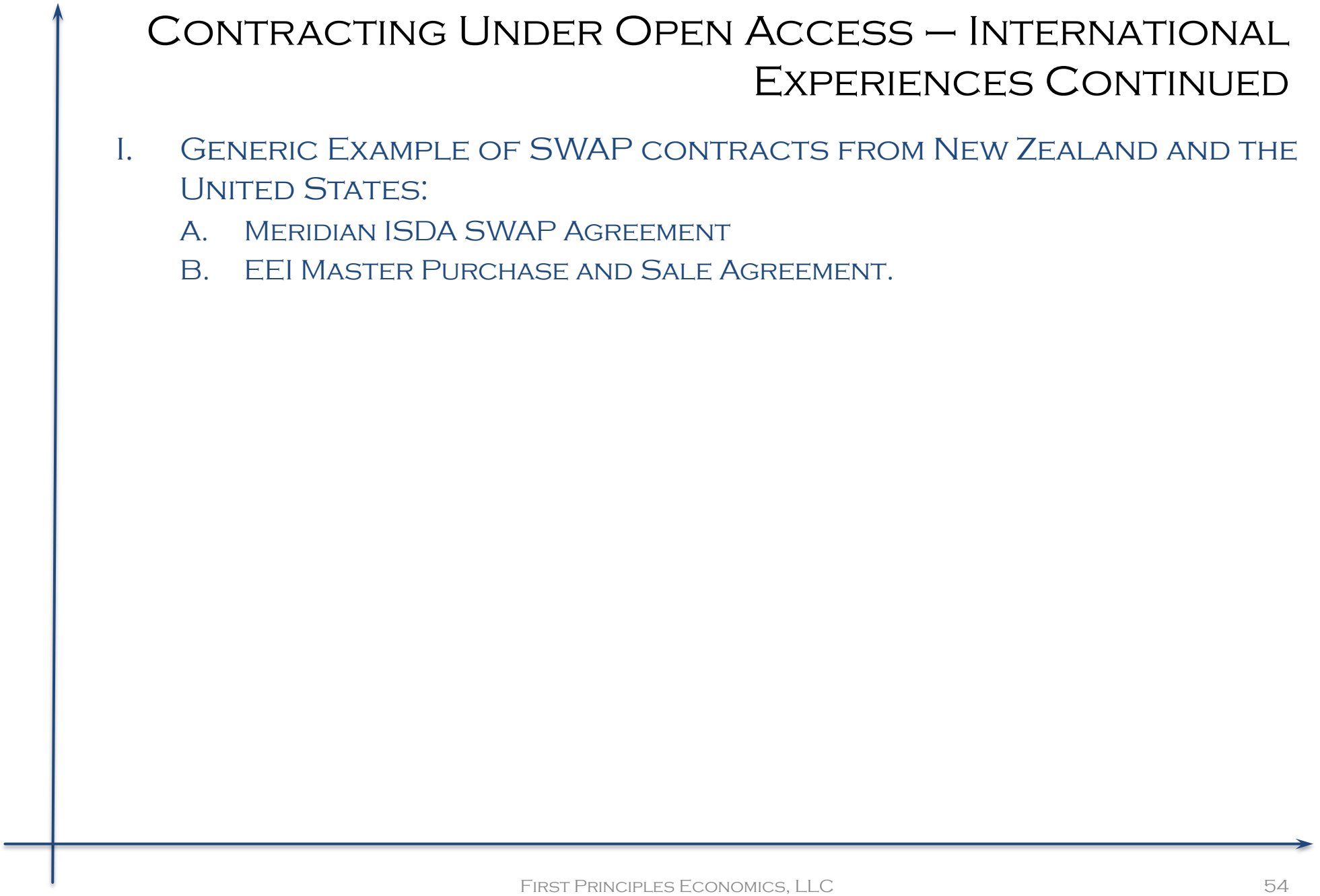
II. Thus there are different contracting structures for jurisdictions that have used financial transmission rights as compared to physical transmission rights.

III. The dominant structure used in areas that rely on financial transmission rights is a "swap" or contract for difference (CFD).
   A. A CFD is a financial contract whereby a price is agreed to bilaterally between a "buyer" and a "seller"…and the contract then settles against the real time or physical price. For example, suppose an electricity consumer and producer agree to buy and sell power at $50. This is the bilateral price. If the physical price, i.e. spot price turns out to be $55…then the generator would rebate to the buyer $5, i.e. the amount over the bilateral price. Similarly, if the price was $45 then the buyer would pay the generator an additional $5.

IV. CFD's require an index or spot price, i.e. a price to settle against. In most electricity markets this price is the physical spot price.
   A. In this way, the financial contract settles against the physical price.

Contracting Under Open Access – International Experiences Continued

I. Generic Example of SWAP contracts from New Zealand and the United States:
   A. Meridian ISDA SWAP Agreement
   B. EEI Master Purchase and Sale Agreement.



Generator Bilateral Contract in New Zealand

ISDA®

International Swaps and Derivatives Association, Inc.

2002 MASTER AGREEMENT

dated as of .....

between

[.....]

("**Party A**")

and

Meridian Energy Limited
("**Party B**")

have entered and/or anticipate entering into one or more transactions (each a "Transaction") that are or will be governed by this 2002 Master Agreement, which includes the schedule (the "Schedule"), and the documents and other confirming evidence (each a "Confirmation") exchanged between the parties or otherwise effective for the purpose of confirming or evidencing those Transactions. This 2002 Master Agreement and the Schedule are together referred to as this "Master Agreement".

Accordingly, the parties agree as follows:—

1. Interpretation

(a) ***Definitions.*** The terms defined in Section 14 and elsewhere in this Master Agreement will have the meanings therein specified for the purpose of this Master Agreement.

(b) ***Inconsistency.*** In the event of any inconsistency between the provisions of the Schedule and the other provisions of this Master Agreement, the Schedule will prevail. In the event of any inconsistency between the provisions of any Confirmation and this Master Agreement, such Confirmation will prevail for the purpose of the relevant Transaction.

(c) ***Single Agreement.*** All Transactions are entered into in reliance on the fact that this Master Agreement and all Confirmations form a single agreement between the parties (collectively referred to as this "Agreement"), and the parties would not otherwise enter into any Transactions.

2. Obligations

(a) ***General Conditions.***

(i) Each party will make each payment or delivery specified in each Confirmation to be made by it, subject to the other provisions of this Agreement.

(ii) Payments under this Agreement will be made on the due date for value on that date in the place of the account specified in the relevant Confirmation or otherwise pursuant to this Agreement, in freely transferable funds and in the manner customary for payments in the required currency. Where settlement is by delivery (that is, other than by payment), such delivery will be made for receipt on the due date in the manner customary for the relevant obligation unless otherwise specified in the relevant Confirmation or elsewhere in this Agreement.

Master Version: Electricity - No credit support documentation required

ISDA

International Swaps and Derivatives Association, Inc.

SCHEDULE
to the
2002 Master Agreement
dated as of **[ ]**

between

Meridian Energy Limited And **[ ]**

("Party A") ("Party B")

Part 1. Termination Provisions

(a) ***"Specified Entity"*** means in relation to Party A for the purpose of:-

Section 5(a)(v), N/A

Section 5(a)(vi), N/A

Section 5(a)(vii), N/A

Section 5(b)(v), N/A

and in relation to Party B for the purpose of:-

Section 5(a)(v), N/A

Section 5(a)(vi), N/A

Section 5(a)(vii), N/A

Section 5(b)(v), N/A

(b) ***"Specified Transaction"*** will have the meaning specified in Section 14 of this Agreement. ***[Unnecessary, commodity swaps and options are already included in the definition of "Specified Transaction"]***

(c) The ***"Cross Default"*** provisions of Section 5(a)(vi) will apply to Party A and will apply to Party B.

Notice the Differences in the Contract Language...

Existing language in PSPA:

2.1.1 Sale of Electrical Power and Energy

The Seller shall within the terms of the Agreement deliver and sell in each Contract Year a maximum demand of .....MW and average demand of .....MW of electrical power and energy to the Purchaser at the designated connection point(s) on the NITS...

2.1.2 Passage of Risk and Title

The Seller shall deliver electrical power and energy to the Purchaser at the Connection Points on the NITS as agreed in the Connection Agreement between the Seller and the designated Transporter and the electrical power and energy shall be delivered in accordance with the TSA between the Purchaser and Transporter. The risks and title thereof shall be deemed to have passed to the Purchaser.

3.4 Subject to any scheduled and unscheduled maintenance requirements and events of force majeure, which may prevent the Seller from doing so, the Seller shall deliver the electrical power and energy as commercially continuous twenty-four (24) hour every day in the year except as otherwise provided in this Agreement.

8.2 Accuracy of Forecasts

If, the power consumption by the Purchaser is higher than 5% of the annual forecast, the Seller reserves the right to charge the actual verifiable marginal cost for the additional electrical power and energy...

In contrast there is no requirement in the ISDA contract structure for Meridian to physically deliver energy. Meridian may choose to deliver physical electricity but the contract does not require it to do so.

Generator Bilateral Contract in the United States

- In the US, bilateral contracting in the electricity sector occurs either via the EEI Master Power Purchase and Sale Agreement or equivalently through an ISDA with a Power Annex. The language of the power annex is identical to that contained in the EEI Master Agreement.
- Notice the heritage of the physical rights model in the language contained in the Master Power Purchase & Sale Agreement.

Master Power Purchase & Sale Agreement

EEI Edison Electric Institute

Again Notice the Differences in the Contract Language

In the EEI Agreement the relevant language is:

- ARTICLE THREE: OBLIGATIONS AND DELIVERIES

  3.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, ***or cause to be delivered***, and Buyer shall purchase and receive, ***or cause to be received***, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

  3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point ***and shall Schedule or arrange for Scheduling services with its Transmission Providers***, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

Notice the generator has no requirement to actually produce the electricity…rather they must "cause to be delivered"…symmetrically the Buyer does not need to physically consume the power, rather they must "cause to be received."

Contracting Under Open Access – International Experiences Conclusions

I. These two examples provide a window on where contracting in Ghana will transition to over the next 5-10 years as competition in the electricity sector and the associated policies of open access take place.

   A. Contracts will no longer be "physical"…this does not mean that generators will not physically produce electricity…it simply means the contracting structure will evolve so that the contract does not mandate the generator deliver electricity to a specific point or else they are in breach of the contract.

I. The contracts provide guidance for how the new PSPA between VRA and its customers should be structured.

I. The Proposed PSPA is an intermediate step towards where the industry will likely end up.

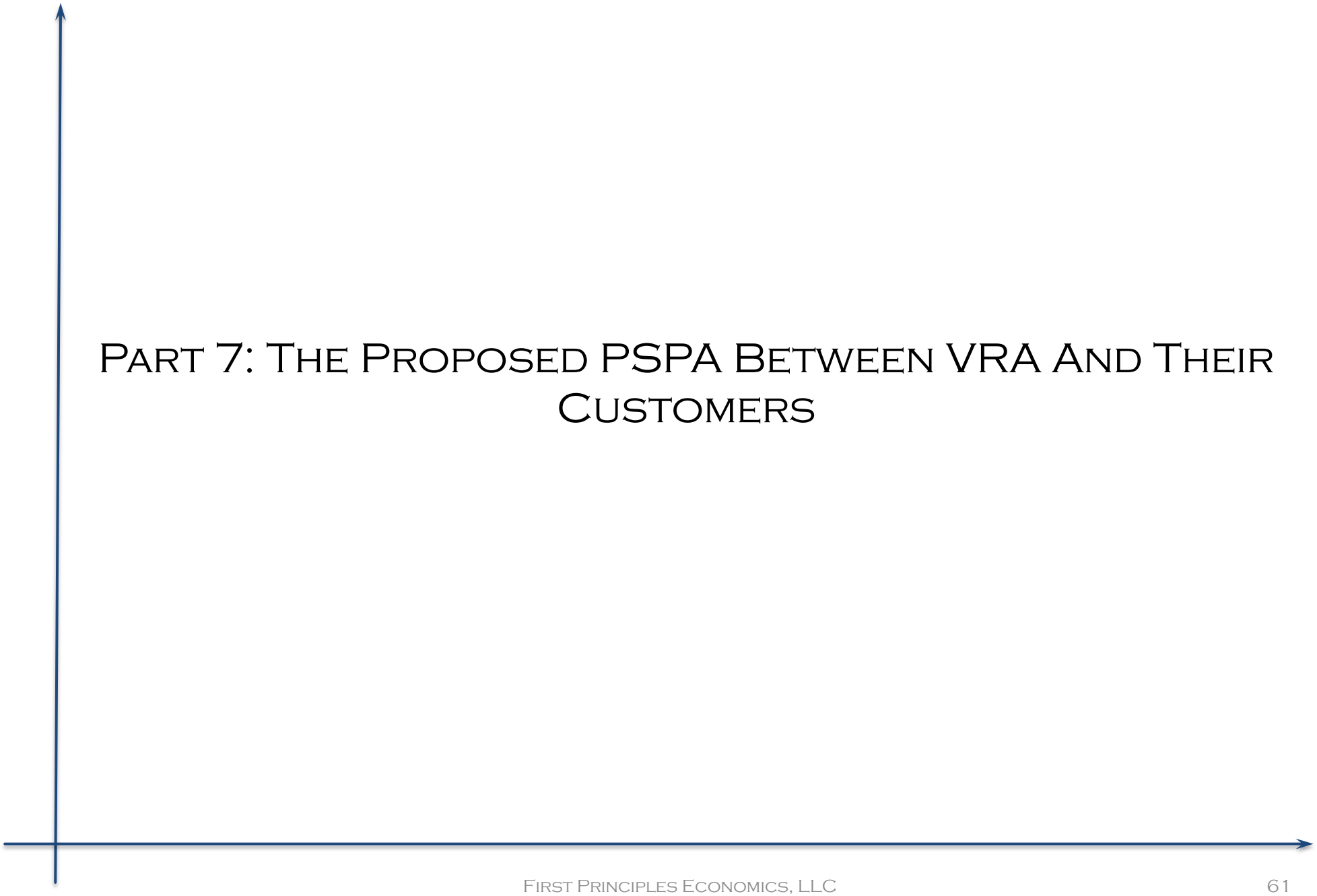
The Distinction between Physical and Financial Bilateral Contracting is a Red Herring

From Wikipedia:

A red herring, according to the Oxford English Dictionary (OED), is a clue which is intentionally or unintentionally misleading or distracting from the actual issue. The term is mostly used to claim that the argument of another person is not relevant to the issue being discussed. In mystery fiction, a clue or lead that turns out not to be relevant to the solution of the mystery would also be a red herring. In a literal sense, there is no such type or species of fish as a "red herring";

Once it is on the grid…all electricity is the same…there is no difference between power that has been sold under a so-called physical contract as compared to power that has been sold under a so-called financial contract.

Discussion/debate over physical and financial is, in almost all cases, a red herring.



Part 7: The Proposed PSPA Between VRA And Their Customers

Guiding Principles for the PSPA

I. While there are a number of issues that need to be solved in order to fully implement non-discriminatory open access we must develop a PSPA that:
   A. Aligns the bilateral contract structure with the changes that have taken place in the industry;
   B. Is forward looking in that it is consistent with where the industry is likely to evolve and move to over the life of the contract;
   C. To the greatest extent possible represents an incremental step rather than a completely new structure,
   D. Facilitates transactions between VRA and their customers while at the same allowing all parties to meet their other contractual requirements.
   E. Enhances overall welfare by allowing for the transparent, fair and equitable allocation of risks, costs and benefits.

II. At a high level the primary changes that must take place in the PSPA relate to the terms and conditions that relate to (1) physical supply and delivery, (2) the way in which deviations from contracted amounts are priced and settled and (3) the fact that GRIDCo is now responsible for dispatching the system and ensuring reliability.

A Note on Pricing Contract Deviations

I. In one sense how deviations are priced is not directly relevant to the PSPA. Earlier in the presentation we discussed that with open access and the presence of at least two competitive generators then which facility serves the additional demand when a customer exceeds their bilaterally contracted amount is a choice made by the dispatcher.

II. As a result the following language from the existing PSPA is problematic for a generator:

> **8.2 Accuracy of Forecasts**
>
> If, the power consumption by the Purchaser is higher than 5% of the annual forecast, the Seller reserves the right to charge the actual verifiable marginal cost for the additional electrical power and energy…

III. Why is it problematic? Why not just charge marginal cost for the MW's consumed in excess of the contracted amount.

- A. What value do we use for marginal cost…different generators (with different owners) may be the marginal plant at different times during the day or even the hour.
- B. If there is at least one constraint then there will be at least two plants that are on the margin, i.e. there will be at least one marginal plant on either side of the constraint.

IV. We could eliminate this problem by somehow requiring customers to "over" contract, i.e. contract for an amount that is greater than their expected peak load.

- A. Not a viable solution.
  - i. Transmission system is already constrained…not feasible to ensure that sufficient transmission capacity is available.
  - ii. Inefficient and costly. In effect, consumers will be paying a premium for every MW of electricity they consume.

V. The question of how to price contract deviations is fundamental to implementing effective and efficient non-discriminatory open access.

Elements of the PSPA

I. The table to the right lists the individual elements of the current PSPA and indicates what sections will need to be modified as well as how significant those changes need to be in order to align the PSPA with the new structure of the industry. In the next few slides we will address the major changes.

Elements of Existing PSPA Structure	Comments
1. Definitions and Rules of Interpretation	Small changes required
2. Scope, Amendment and Effectiveness of Agreement	Changes required
3. Power and Energy Requirements	Changes required
4. Technical Obligations	Changes required
5. Pricing	Small changes required
6. Billing	Small change required
7. Payment	Small change required
8. Load Forecast	Not necessary
9. Power Transmission and Supply	Not necessary
10. Take-or-Pay	No changes required
11. Standard of Performance	Not necessary
12. Continuity of Supply	Small change required
13. Force Majeure	No changes required
14. Safety and Environment	Not necessary
15. Liability and Indemnity	Small changes required
16. Waiver	No changes required
17. Default and Termination	Small changes required
18. Governing Law	No changes required
19. Dispute Resolution	No changes required
20. Assignment	No changes required
21. Confidentiality	No changes required
22. Notices	No changes required

Draft PSPA

POWER SALES AND PURCHASE AGREEMENT

BETWEEN

VOLTA RIVER AUTHORITY

AND

DATED: ……. August 2012

Changes to Clause 2 - Scope, Amendment and Effectiveness of Agreement

I. Existing Language:

2.1.1 **Sale of Electrical Power and Energy**

The Seller shall within the terms of the Agreement deliver and sell in each Contract Year a maximum demand of .....MW and average demand of .....MW of electrical power and energy to the Purchaser at the designated connection point(s) on the NITS...

2.1.2 **Passage of Risk and Title**

The Seller shall deliver electrical power and energy to the Purchaser at the Connection Points on the NITS as agreed in the Connection Agreement between the Seller and the designated Transporter and the electrical power and energy shall be delivered in accordance with the TSA between the Purchaser and Transporter. The risks and title thereof shall be deemed to have passed to the Purchaser.

II. Proposed Language:

2.1.1 **Sale of Electrical Power and Energy**

The Seller shall within the terms of the Agreement make available for delivery in each Contract Year a maximum demand of .....MW and average demand of .....MW of electrical energy to the Purchaser at the designated Delivery Points on the NITS.

2.1.2 **Passage of Risk and Title**

The Seller shall make available for delivery electrical energy to the Purchaser at the Delivery Points on the NITS. The risks and title thereof shall be deemed to have passed to the Purchaser.

Changes to Clause 3 – Power and Energy Requirements

I. Existing Language:

3.0 POWER AND ENERGY REQUIREMENTS

3.1 The Seller shall reserve for and make electrical power and energy available for Purchaser, under the terms and conditions of this Agreement, to be transported to the nominated Point(s) of Delivery on the ETU's NITS as herein specified in Clause 2.1.2.

The Purchaser shall be required to make its own arrangements with transporter for the transmission of the electrical power and energy from ETU's substation facilities.

II. Proposed Language:

3.0 ENERGY REQUIREMENTS

3.1 The Seller shall make electrical energy available for Purchaser, under the terms and conditions of this Agreement, to the nominated Delivery Point(s)on the ETU's NITS as herein specified in Clause 2.1.2.

The Purchaser shall be required to make its own arrangements with transporter for the transmission of the electrical energy from the Delivery Point(s).

Elimination of Clauses 4, 8, 9, and 11

Under the old PSPA VRA – as both the generator and transporter of the electricity – necessarily included physical requirements in the contract.

However, under competition and open access these physical requirements will not be part of the Connection and/or Transmission Services Agreement with GRIDCo.

Moreover, VRA is no longer responsible for transmission planning or metering.

The PSPA is simply a contract for electrical energy.

SUMMARY OF CHANGES

There are six primary changes to the language/clauses of the previous PSPA.

- First, the contract is for energy only.
- Second, The provision of, and payment for, ancillary services will no longer be accomplished through a bilateral contract between generators and their customers. Rather it must come through GRIDCo as the system and market operator. Only GRIDCo will have the information necessary to determine the correct location, quantity and duration of ancillary services. Therefore, the correct contracting structure is for GRIDCo to procure and then charge for ancillary services in either their Connection Agreement or Transmission Service Agreement. Alternatively, GRIDCo could develop precise rules regarding procurement and deployment of ancillary services that would then need to be included in energy contracts.
- Third, the *DEFAULT LEVEL* of service is for VRA to make electrical energy available for delivery at the relevant generator bus. This compares to delivery to the customer's bus.
- Fourth, VRA can no longer unilaterally provide more electricity if there are positive deviations from the contracted amount. Rather GRIDCo will determine which plant will make up the deviations based on real time information and create a spot price which will be applied to these overs/unders.
- Fifth, the Draft PSPA contains credit and collateral requirements.
- Sixth, the Draft PSPA through language in Clause 18 explicitly recognizes the industry is undergoing change.

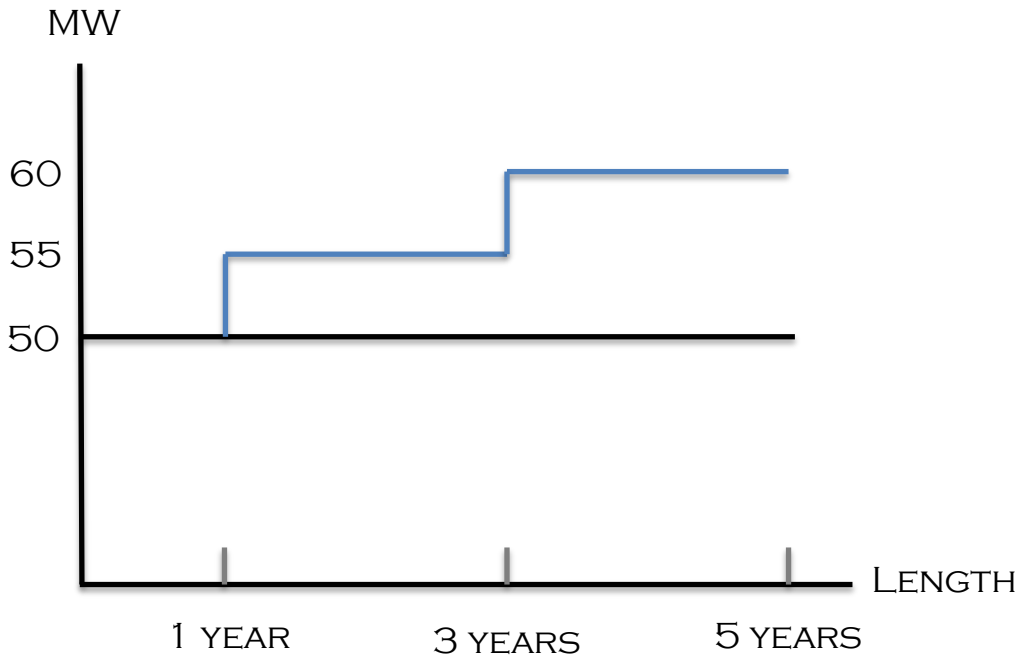
Steps Necessary to Implement the PSPA

I. The contractual structure is predicated on the completion of Connection Agreements and/or Transmission Service Agreements.
   A. Among other matters, these contracts must address the procurement of and payment for ancillary services.

II. Since no single generator can necessarily supply increments above the contracted amount, GRIDCo needs to develop a methodology by which they supply and price positive deviations from bilateral contracted amounts.
   A. GRIDCo needs to facilitate settlement for customers who use more than their bilateral contract amount.
      i. Are incentives necessary to encourage customers to enter into the appropriate level of bilateral coverage?
      ii. Are incentives necessary to encourage customers to follow their contracts?
   B. Pricing and settlement procedures and rules developed by GRIDCo should be consistent with physical operations in balancing supply and demand and maintaining reliability.

Basic Structure of the VRA Power Supply Purchase Agreement - Quantity

I. The basic structure of the new PSPA will be that of a contract for difference (CFD)
   A. How will it work?
      i. VRA will make available energy at the generator bus.
      ii. Price is determined by Tariff Formula.
      iii. Quantity of kWh and Duration of the Supply Agreement are both negotiated.
         - Quantity can increase over the life of the contract
   B. Delivery point will be at the generator bus.
   C. The commodity being contracted for is the capacity to produce the contracted amount of electricity in kWh.
   D. Positive deviations from the contract amount will be charged the "spot price"



Next Steps

VRA has provided a white paper and a draft PSPA for your review and comments.

We welcome and encourage any and all comments…our goal is to meet the needs of our customers while operating efficiently and reliably within the framework created by the Government.

Comments or questions on either the White Paper or the Draft PSPA are due by September 7, 2012

Please send your comments to: