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Feed-in Tariffs (FITs) and Feed-in Premiums (FIPs)

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Toby Couture Good day, everyone, and welcome to this International Solar Alliance Expert Training course. This is session five in this ISA training series, focusing on feed-in tariffs and premium FITs, or what are sometimes called feed-in premiums. This webinar series is part of a partnership between the International Solar Alliance and the Clean Energy Solutions Center. The International Solar Alliance is a network of solar resource-rich countries from around the world focused specifically on scaling up the use of solar power worldwide. And the Clean Energy Solutions Center is one of the leading institutions around the world providing capacity building and technical assistance support to governments and regulators on clean energy policy topics. This training is part of Module 1 and focuses specifically on FITs and premium FITs. We'll provide a quick overview of the presentation before diving in. So, we'll look at the learning objective, the main body of the presentation, have a few concluding remarks, and then there'll be some further reading along with a knowledge check, with a couple key questions based on the content of the presentation. So with that said, let's get started. So, the goal of the presentation is broadly to understand feed-in tariffs and feed-in premiums, how they emerged, how they differ from other renewable energy policies, and also to understand where they're being used, and how, in different jurisdictions around the world. And finally, you should be able to understand the advantages and some of the disadvantages of using each of these different policies.

So let's start with feed-in tariffs. In many ways these are more widely-known policies. You've no doubt heard of feed-in tariffs, but it's important to go over some of the basics to set the stage for better understanding feed-in premiums. So first, feed-in tariffs emerged in the 1970s and 1980s as part of efforts to diversify the energy mix. The first FIT was launched in 1978 under the US PURPA laws, which are the Public Utilities Regulatory Policies Act. And this law under the energy policy act of 1978 basically provided the obligation that utilities would have to purchase generation from non-utility generators, what are called qualifying facilities, at their avoided costs. One of the reasons behind this was in the context of the energy crisis in the 1970s, there was a huge priority to diversify the energy mix and encourage more investment in alternative sources of generation. And as part of this, these was also an increasing skepticism or increasing calls to question the traditional monopoly status that utilities had benefited from. And as part of this, regulators said—or lawmakers in this case, in the PURPA Act, essentially said utilities will be required to accept generation from third-party developers, third-party investors of different technology types, so long as the purchase price is not higher than the avoided costs of generation that the utility itself would have to incur. So this was a fairly revolutionary shift in the power sector for a wide range of reasons. And much has been said and written about the impact of PURPA. What interests us here is the role that this policy played in catalyzing a number of other developments like it around the world, taking this core idea of allowing third-party people, third-party generators, third-party investors, to supply electricity in the traditionally monopoly system and receive a fair price for that generation. So in the 1980s a few countries in Europe started to pick up on this and realize that this is something that they could do as well. There were a few subnational attempts to introduce feed-in tariff-like policies in countries like Spain, in countries like Germany and Switzerland. And Germany was the first on a national level to introduce a FIT in 1990, which entered into force in 1991, shortly after the Berlin Wall came down. The national level of FIT at the time was based on a percentage of the retail price, so the German approach originally deviated from this avoided cost-based approach that was common in the US, which had its own issues. Germany wanted to encourage more distributed and decentralized power supply and introduced a somewhat more generous pricing scheme based on a percentage of the residential retail price, which also again is not necessarily the most intuitive benchmark for pricing renewable energy technologies. Nor were avoided costs, for that matter, but this is where the policy essentially started and has developed further from there. So, in Germany's case the first feed-in tariff law, where we actually get the word feed-in tariff from, introduced different prices for different technologies based on different percentages of the retail price. So, technologies like biomass received 65 percent of the retail price, technologies like wind and solar received 90 percent of the retail price, and so on. Feed-in premium policies emerged somewhat later in the evolution. So, the basic formula for a feed-in tariff is a cash payment based on the cost of generation for that technology, so this is really the classic formula for modern or advanced feed-in tariff policies that are widely used around the world. They can be differentiated by project size; by location of the project; by the resource quality found in that region or for that specific project; and by year, so different projects connecting to the grid at different times can get different prices. The key feature that differentiates most feed-in tariffs from the range of other policies that have been used, such as net metering or net FITs, which we've treated in a previous training session, is that the customer receives a check for 100 percent of their output. So essentially whether you're a household, a business, a larger developer, you are exporting your power 100 percent to the grid, and you are getting paid for all of that supply. So in most cases under classic feed-in tariffs, there's no self-consumption. It's 100 percent export oriented, even if the solar system is directly on your roof. As we saw in the training session on net FITs, there are some jurisdictions like Australia that have taken a different approach to this and have structured their feed-in tariffs to allow self-consumption from the beginning, so that it was already premised on the idea of self-consumption—that you would first consume your power on site and only export your surplus generation to the grid. But classic FITs were based on 100 percent of the output.

They contain three key elements: a clear price for electricity sold to the grid; a clear long-term contract; as well as guaranteed access to the grid. The first comprehensive definition of feed-in tariffs was provided in 2000 under Germany's Renewable Energy Sources Act, where it updated its original feed-in tariff law and introduced a formal Renewable Energy Sources Act that took the policy several evolutionary steps forward. Specifically, in Germany's 2000 feed-in tariff it introduced cost-based compensation, and you can see the definition here. "The compensation rates specified have been determined by means of scientific studies, subject to the proviso that the rates identified should make it possible for an installation—when managed efficiently—to be operated cost-effectively, based on the use of state-of-the-art technology and depending on the renewable energy sources naturally available in a given geographic area." So there you really have the core principle behind cost-based feed-in tariffs. If wind power costs $0.08, then the off-taker or the buyer of that electricity should pay $0.08. If solar power costs $0.05, then solar power should be purchased at $0.05, based on the naturally available resources and a series of assumptions around the operational efficiency and performance of an average or a standard solar installation. So the basic logic is there. It enabled feed-in tariff essentially calculation tools to be developed. It allowed the calculation of appropriate, cost-reflective tariffs for different renewable energy technologies. As you can imagine, this gets quite sophisticated when you start getting into biomass technologies, where you have in some cases multiple different feed stocks, different heat rates, different efficiencies, and all of that needs to be taken into consideration—and in the German case is taken into consideration—in the development of multiple different tariff structures for biomass technologies, in particular. Comparatively for wind and solar, the calculations are fairly straightforward.

So taking a quick look at FIT design, and how they're actually structured. Feed-in tariffs guarantee a pre-established payment for renewable electricity for a specific period of time, typically from 15 to 25 years. In some cases, it's as short as 10 or 12 years, but broadly most feed-in tariffs are between 15 and 25. The returns on investment can be calculated based upon the time period of the contract as well as the tariff payment level that's offered, and it allows essentially in the calculation model to target a specific internal rate of return, or an IRR. The key here is that the feed-in tariff price is independent from, and thus unaffected by, fluctuations in the market price of electricity—the key reasoning there being that it should provide investment certainty, or at least investment security, for developers and thereby help scale up investment in these different renewable energy technologies. Now, there are a number of additional provisions that have been added in over time. Priority dispatch—we're requiring that renewables get dispatched before other sources, so essentially a priority purchase. Inflation indexation—in some countries there's an indexation so that the tariff level actually goes up every year, to track the increase in the consumer price index. Annual degression works in the other direction. It says that projects connected to the grid in future years should receive a lower price because technology is getting cheaper and more efficient. So as you see here in the little chart, degression essentially provides a different tariff for projects connected in subsequent years. There can also be caps, a wide range of technology differentiation, forecast obligations for projects beyond a certain size, and so on. So there's a range of different design elements that go into making a feed-in tariff policy function beyond just the tariff. Much of the emphasis tends to focus on the tariff, but in order to have a successful policy, a range of different regulatory provisions and designs are required. By providing long-term contracts, the fundamental goal of feed-in tariffs is to provide long-term investment certainty. And because renewable energy projects are often small, at least small by traditional power sector standards for generation assets—namely under 100 megawatts—some have argued that it's inefficient to issue RFPs, or requests for proposals, for every individual capacity addition, because it's administratively quite burdensome to issue RFPs for such small projects. This makes standardization possible, even desirable. So FITs aim to essentially achieve that by providing a streamlined process to allocate renewable energy contracts to eligible producers based on standardized pricing and contract conditions. The idea being if there are hundreds of potential sites for the development of solar power in a given country, the regulator posts the price and provides information regarding the contract terms, and individuals, companies, cooperatives, developers can look at that information and make a decision whether it makes sense for them to invest and build their project in their region, based on their own calculations and based on their own profit expectations. But the key there is that the terms are public, so there's no bilateral deals, no hidden contracts. All the information, typically, under a feed-in tariff is made available online. Standard contract terms for everyone, so you essentially know if your neighbor connected their project in 2011, you could, by going online, find out effectively what contract terms were for that project built in 2011. The idea is part of the shift in the power sector away from more nontransparent means of contracting towards a more transparent platform for contractual relations, where you can actually see what producers are getting, and ultimately gain a better understanding of the overall power sector in the process. Where contracts are not public, as typically the case with larger facilities, larger coal plants, larger nuclear plants, feed-in tariffs have tried from the beginning to get away from that, and to essentially make the information public, in the interests of more transparency.

So let's have a quick look at some advantages and then some disadvantages, 'cause it's not all positive and rosy, either. So as we pointed out, FITs provide long-term investment certainty. They provide clear, transparent prices. They've been a very successful mechanism at encouraging renewable energy investment. They remove the off-taker risk for different developers. They provide a high degree of investability or bankability in renewable energy projects. They can be differentiated, so that larger projects get a slightly lower tariff than smaller projects due to economies of scale, and so on. And feed-in tariffs can also be designed to encourage technological innovation and cost reduction via mechanisms like degression, so that you encourage developers in future years to continually reduce the costs and effectively both track and encourage the reduction in project costs as the market matures and as the technology matures. And finally, FITs can work quite well for both small-scale RE projects as well as large-scale projects, and they have been, worldwide, one of the most successful policy mechanisms at scaling up new investment in the sector. There is, however, according to many, a shift away from feed-in tariffs, and we're going to get into a little bit of that, part of that shift. And one of the ways in which that's manifesting itself is in the shift towards feed-in premiums. And we'll get into why that's important and what that tells us in a moment. Now, some challenges. Some critics argue that government shouldn't be the one setting the prices for renewable energy contracts, markets should, and therefore that the whole principle of feed-in tariffs—namely, that the government can calculate the prices and set them—is fundamentally flawed, and that rather prices should be set via competitive auctions or competitive procurement, so that you effectively have price discovery through the market mechanism rather than through internal government calculations. This remains one of the perennial criticisms of feed-in tariffs. Connected to that is the concern that the FIT rates will be too high, in other words too generous, and won't be successful at tracking technology cost changes as efficiently as a policy like auctions or competitive tendering would, which would track the market cost at that particular point in time when the auction is launched. And, in fact, this does remain a very legitimate criticism. We've seen in many different jurisdictions around the world, from Japan to Malaysia, even according to some here in certain periods in Germany, where the FIT rates have been too high, have been too generous. And some have criticized feed-in tariffs along these lines as contributing to market boom and bust cycles, where you have very rapid development, very successful development, and then a bust when the government realizes, or the utility realizes, that there are too many projects being built. And this kind of boom and bust cycle is very negative for long-term investment certainty. So there's a good argument to be made there that this has been a concern and remains a concern for long-term market stability and long-term market growth. Some argue, in fact, that FITs have driven too much renewable energy development too fast, and that they're in that sense harder to control than an auction mechanism, where you can effectively tender out blocks of capacity. Say we want 500 megawatts now; we'll have 500 megawatts next year; and you can procure effectively on a predetermined schedule. That criticism remains a concern of many regulators and many utilities who have been trained in a more sort of central planning paradigm, particularly within utilities, where they like to be able to do planning around generation adequacy, around generation mix, and have control over that. Now, some argue that all of that's changing, as markets are becoming more liberalized, and we need to move away from this sort of command-and-control, central planning approach to the operation of the power sector. But in many electricity markets around the world, they remain single-buyer markets, where there's one utility basically operating the power system and who's responsible for reliability, and in those contexts, these kinds of arguments tend to be fairly important and remain so. Some criticize feed-in tariffs also by saying that they're less compatible with liberalized electricity markets, because the principle behind liberalized electricity markets, as we'll see in a moment, is that generators should be competing in real time and receive the prevailing market price—not some contractually determined price that's locked in. So some argue that this incompatibility means that we need to fundamentally move away from feed-in tariffs and transition everybody to dynamic pricing. A further criticism is that FITs provide utilities with less control over the location of RE projects. This remains true. If feed-in tariffs are open ended, it's harder to determine exactly where projects will be built, because projects are built from the bottom up by citizens, communities, investors, farmers, and therefore it makes it more difficult to adequately control the actual location of each project.

So, with that said, let's dive into feed-in premium policies, or what are sometimes called FIPs, instead of FITs. The basic formula with the feed-in premium is a premium payment that's either fixed or floating, received on top of the market price. And these different premiums can be differentiated based on the cost of the technology. So you can have a larger premium for a less mature technology, and a lower premium for a more mature technology. The emergency of premium FIT policies is closely linked to the emergence of competitive electricity markets. As a wholesale market emerged in countries across Europe, in particular, a number of regulators and policy makers started to want to expose renewable energy projects—in fact, all generators, ultimately—to these spot market prices, so that in periods of scarcity they could bring more supply into the market and help correct the prices downward. So the idea being that competitive electricity markets will be a better mechanism for controlling supply and demand, and ultimately keeping prices low. In that regard, in contract to fixed FITs, or feed-in tariffs that offer a long-term contract or a long-term purchase obligation that guarantees a certain price, in this case a producer, a generator under a premium FIT, or a FIP policy, would be selling their power directly on the wholesale market. And the idea, the goal of the premium in this case is to top up those spot market revenues. And you can see there here, captured in the graph to the bottom right. Now, as electricity markets were liberalized, there was a push to improve the market orientation of feed-in tariff policies. Spain was the first to adapt the feed-in premium option in 2004, providing premium prices for wind power and other technologies. And the premium effectively is designed to only represent a portion of the total revenues obtained by the project. The rest are derived from market sales. So the idea is effectively to cover the gap required in order to ensure the projects can be profitably developed. Now, there are multiple ways of structuring feed-in premiums, so let's have a look at some of the main options out there.

This is in some ways the classic fixed premium, which hovers above the wholesale market price. In this case, in the graph it's shown as the retail price, but that's really essentially the market price. And the feed-in tariff then corresponds with the market price plus that premium. That premium could be 2 cents per kilowatt hour; it could be 5 cents per kilowatt hour, and it would essentially track those market prices over time. The problem with this approach is that it risks over-compensating producers when market prices go up, because the premium is fixed. So even if market prices go up to, say, \$200.00, \$250.00 per megawatt hour, producers will still receive the premium. So in response to some of those concerns, we've seen an evolution to different, more sophisticated feed-in premium designs. So this second option is a variable premium that introduces caps and floors. And it takes a minute to wrap your head around this particular approach. This is a sketch of the Spanish wind feed-in premium from 2007, and you can see the key line here is the red line, the development of the actual remuneration for the project. So you can see from zero to \$0.042 cents per kilowatt hour, roughly, as long as the market price is there, the producer will receive just over \$0.07 per kilowatt hour. And if the market price goes a bit above that, it'll trace up to about \$0.085 per kilowatt hour. It'll stay at \$0.085 until \$0.085, and then anything above \$0.085 will then effectively allow the developer to receive the market price. So if prices go up to \$0.15 per kilowatt hour, then the wind developer would just get \$0.15, essentially gaining the windfall profit from that. So you can see here that even if electricity market prices are quite lot, namely below, in this case, \$0.085, the developer is secured of receiving somewhere between \$0.07 and \$0.085 cents, rather than simply the market price, which may be below that. So the idea there is to try to provide revenue security against the downside risk of market prices collapsing, while still providing the upside potential of gaining when electricity prices increase beyond that level. So in that sense, particularly for non-wind technologies—let's say biomass—if they were capable of ramping up production further when prices go beyond \$0.085 per kilowatt hour, then you could help curb the prices back down effectively by encouraging more supply to enter the market. So this is the basic principle of the variable premium model with caps and floors. So in this case the cap is partial, so there's a cap only within that \$0.085 range, and then if prices go beyond that, then the remuneration goes up as well. Some policies have taken this a step further, as we'll see in a moment.

The third approach is what's been called the spot market gap model, which basically allows the market price to do what the market price will do, and covers the gap between that and the estimated required feed-in tariff price. So basically here in the light blue line you can see the minimum payment guarantee or the minimum feed-in tariff level, and the spot market revenues are insufficient, or are most of the time below that. Therefore a premium goes in to cover the difference between the spot market price and the required price in order for the project to be bankable. Now, in this case the interesting nuance is that if the spot market price is high enough, the premium goes to zero. And in this case, different policies will approach this differently. You can either track the market price, as in the Spanish example; or as we'll see in a moment in another variation, you can require the producer to pay that back, so that they don't benefit from the windfall profits. So essentially the spot market gap model is very similar to the more sophisticated Spanish cap and floor model, but it essentially is related in terms of its design. A key issue is how the actual benchmark price is determined. So you have this electricity market price, but in a real-time electricity market, prices can fluctuate over seconds, minutes, 15-minute intervals, hour intervals, day intervals, you have a day ahead market—The key question becomes, what is the benchmark that the premium is fluctuating on top of? Because this has a very significant impact if you're a wind or solar producer; you're producing in real time. Is your revenue also going up and down with the market price on ever-15-minute intervals, or is the system designed to be averaged over hours or over days? And again, these have very significant impacts on the financial side of the calculations, but basically the idea is that the spot market price should be the benchmark, and anything above that should be explicitly paid by this premium, which also enables you in a way to isolate the policy costs, because you can calculate the sum of those premiums, and estimate the total cost of the policy.

Now, an important nuance there regarding costs. It's difficult to separate the causality in many cases. Wind and solar power tend to produce when it's sunny and when it's windy, which can have very direct and very real effects on wholesale market prices themselves, if there's enough wind and solar installed capacity in the system. So in some sense, wind and solar projects can contribute—and we've seen evidence of this throughout jurisdictions around the world—they contribute to actually reducing the wholesale market prices. So there's a bit of a paradox there, in that wind and solar could, when they're abundant in the system, actually push wholesale market prices down, in some cases even negative, which thereby increases the premium payment required, because they have contributed to producing these lower wholesale market prices through their abundance. And with lower market prices means a higher premium gap that needs to be covered. And this has been a very key debate in Germany to which there hasn't yet been a satisfactory solution in the calculation of the total renewable energy support surcharge costs. It's still basically premised on this idea that it's the gap between the market price and the payment price issued to the different developers. And that's problematic, again, because of these causal effects that renewable energy can have on wholesale market prices. So again, very important debate there, and very important nuance in all of this, to which there has yet to be a fully satisfactory solution.

Now, let's look at one other variation along these lines. It's very similar to the spot market gap model called contracts for differences, or CfDs. CfDs are based on a strike price between the generator and the off-taker. So the developer will propose a strike price. If the off-taker agrees, they will set that. In this diagram here you can see—this is from the British case—locked at £70 per megawatt hour. And basically the strike price is what the generator will receive, so long as the price is below £70. And if the price goes above £70, then the generator has to pay that back. So essentially it provides revenue certainty against downside risk, but it takes away the upside windfall profits, if profits go above. And you can see here that this has attractive features. It can provide revenue certainty on the one hand while reducing policy costs on the other by avoiding some of these windfall profits if profits skyrocket. So number of jurisdictions are now starting to look at modifying either their feed-in tariff policies, or their feed-in premium policies, towards something like a CfD. And there are good examples of that across Europe. CfDs are not without their own issues, and, again, the devil is in the detail in terms of how they're designed. But for jurisdictions with competitive wholesale spot markets, CfDs are emerging as a viable policy option to support renewable energy investment. Again, not without their challenges, but all policies have pros and cons. Different rules with regards to CfDs and caps and floors can determine whether windfall profits are given up. And also, critically, if prices go negative—in other words, if wholesale market prices as a whole go negative—what happens? And if prices go negative, then in many cases the consensus that's emerging is that all generators on a network should have to suffer a little bit of the responsibility for having contributed for negative prices. So the challenge becomes how to allocate that burden sharing, with regard to the creation of negative pricing. But that gets into a separate issue, or a separate set of topics that we don't need to get into today.

The important thing is to understand, again, how different feed-in premium policies work, and what are some of the design nuances that are involved, and some of the arguments for and against. So, on the one hand, with a feed-in premium generators take on more price risk, because the wholesale market price that they're taking is fluctuating. As a result, they are typically believed to result in higher overall policy costs, because if investors have higher risks, they will need to price in those higher risks in the form of higher returns. And that has led to some concerns and some criticism of, why are we moving away from feed-in tariffs that provide higher investment certainty in favor of feed-in premiums, which provide less and less uncertainty, depending on the design? A further challenge is that just because market prices go up, let's say wholesale market prices, wind and solar operators in particular can't easily, credibly, realistically make the wind blow harder or the sun shine more. They are effectively taking the wind and the sun as it comes, and they are maximizing their production in order to maximize their revenues, in most cases. Now, the basic idea of a feed-in premium is that producers should modulate their supply if pricing conditions dictate. The challenge with that logic is that it's not easy for wind and solar projects to throttle themselves, in other words to ramp up and down, or to curtail themselves from their own output, because effectively they're then losing revenue if they give up some of the wind that's blowing, and give up some of the sun that's shining. So the logic there is problematic, because it comes back to the original logic of the power sector liberalization reforms that were based on dispatchable sources of generation, in particular natural gas turbines. And with a natural gas turbine you can very quickly ramp up and down to respond to price spikes. And that logic does not transfer very well to wind and solar projects, so it's led to some concerns that this is in a way a maladapted policy tool, because it effectively creates a series of incentives that wind and solar in particular can't respond to, because they can't force the sun to shine more brightly or can't call on the clouds to go away, and likewise the wind developers can't increase the wind flow.

So there's a set of issues there that point to problems, particularly for wind and solar. For biomass technologies or hydropower for example, this may actually not be a problem at all. In fact, biomass and hydro can respond typically to price signals and can ramp up or down their output, depending on market prices. So this is one reason why some countries are increasingly trying to adapt their feed-in premium policies to provide incentives specifically to dispatchable renewable energy technologies like biomass and hydro, so that they can tap into some of that flexibility. Because under a fixed feed-in tariff, a biomass project, for example, will have an incentive to operate like a nuclear power plant, basically at 90 percent-plus capacity factor all the time, just so that they can maximize their revenue. But that may not be the best use of that asset for the power system as a whole. There may be benefit in trying to unlock some of that flexibility so that biomass producers can respond to price signals, produce less when prices are low or even are negative, and produce more when prices are high. So in that sense, a more dynamic feed-in premium type approach may be best suited for technologies that are dispatchable, like biomass and hydro, so that we can unlock some of these technologies' flexibility in the process. Now, again, this debate continues to rage on, and in many European countries wind and solar have also been brought into the fold and are, at least for projects beyond a certain size, are offered variations on feed-in premiums. But again, these background issues remain real in many cases, and we are still in some ways exploring new policy designs that help address some of these challenges. And one of these pathways that's been discussed would be something like contracts for differences, with different types of strike prices for different dispatchable and nondispatchable technologies. But again, it's too early to say where this discussion is going to unfold in the years ahead.

So as we saw earlier, as we discussed earlier, feed-in premiums in general were believed to yield higher returns than feed-in tariffs, at least in some of the key markets that first adopted them. And you can see here, following Spain's 2004 reforms, where they introduced the premium option, a growing share of the market for wind power started to adopt the premium option. So it went from basically zero in 2004 up to somewhere around 80, 90 percent of the market thereafter already two years later, in 2006. So the shift there was quite clear, and this underscores the key point here, is that policy design matters, and developers respond to policy signals. So the change from a fixed option to a premium option—Again, they were not obligated to switch to the premium; this was a free choice. They were presented with a voluntary option. And you can see here how the market responded, suggesting indeed that the premium option was expected by most actors to offer higher returns. This is the state of play currently, from the most recent map I could find in Europe. And you can see here countries with feed-in tariffs, countries with feed-in premiums, or both; quotas; as well as tenders and auctions. Now, technically Germany is also experimenting with auctions, as is the Netherlands, so some of these countries should actually have three colors. In fact, as a rule, a growing number of countries have multiple policies, not just one dominant policy, to encourage renewables. And one of the key questions becomes how to combine different policies, how to combine auctions, and potentially feed-in tariffs or feed-in premiums, with net metering or with net billing or net FITs, into a comprehensive workable policy package to encourage investment at all scales. So that gives you a sense, a little bit, of the landscape across Europe currently. Now, if we take a look at some of the overview of the policies themselves, this retraces some of what has been covered in the net metering and net FIT presentations, but adds in both the classic FIT as well as feed-in premiums at the bottom. FITs are based on the LCOE of each technology. Premium FITs are fixed to a floating price over the market price, but again, often with the core idea of setting a price that's based on the LCOE in the process. So premium FITs strive for technology-specific, cost-reflective pricing. They just get to that end by using market prices and by exposing, or requiring in many cases, developers to export their power, sell their power directly, market their power directly onto the wholesale market. So in some ways it's an operational difference, in that developers under a premium feed-in tariff have to go through the mechanics of actually marketing their power, often in real time, or on the day-ahead or hour-ahead markets, onto the spot market, rather than under a FIT, where essentially it's just a guaranteed off-take. You meter the output, and you get paid for that, and somebody else deals with it, in terms of marketing that and distributing it, and so forth. So some important differences there. This just captures essentially the generic overview.

Now, let's look at some advantages and some challenges for feed-in premium policies. As we've seen, feed-in premiums are better adapted, arguably, to liberalize the electricity markets that feed-in tariffs. They require developers to, in most cases, market their power directly, so there's no intermediary. Or often, if there is an intermediary, it's a market intermediary who is buying that power and essentially taking care of it as a service, before then wheeling it on into the power system. The key difference there is that the price that the developer receives is essentially made up of two components rather than just a FIT payment, in the case of a feed-in tariff project. In this case it's comprised of two components: the market price plus this fluctuating premium, which is often calculated after the fact, or what we call ex post. And typically that methodology effectively involves what's often called a top-up for the revenues over the course of, say, a calendar month, or in some cases even a calendar year, where the calculations can then be done, can be certified or audited, and then a payment made for the difference reflected by this premium. Feed-in premiums arguably provide an incentive to supply more power to the grid during peak times. This is particularly the case for technologies that can increase their supply during peak times, as we saw like biomass potentially and hydro. Feed-in premiums can still, despite the fact that they're more market-based and that they involve arguably a bit more price risk, depending on the design, they can still provide revenue certainty via the use in particular of caps and floors. So the idea again is to try to make renewable energy support policies more market compatible, more market integrated, while taking care of the revenue fundamentals, the financial fundamentals required to make projects investable. Because the consequence of forcing everybody to go onto the spot market would likely be that many projects across the market would no longer be investable at all. And that's not just renewable energy technologies. In fact, if you listen to the head of some of the major European utilities in recent years, the wholesale power market is not providing the kinds of price signals required for any generation technology to be financed entirely via the spot market. So what we're seeing is contracts sneaking their way back in, people signing bilateral contracts, various forms of fixed-price contracts for shorter, medium, long-term duration, and we're seeing the introduction of, for renewables, policies like fee and premiums that enable the market dynamics to continue and to be the benchmark, but provide a top-up to that revenue to provide revenue certainty. Premium policies arguably also lead to lower system integration costs, because in theory developers will need to be more price responsive, will need to avoid times of congestion, and will tend to result in also better project siting in the long run so that areas—at least in a nodal power market system like in Italy, where there would be an incentive for the zones of the power grid where higher prices are found to develop more projects in those regions, because they could benefit from higher spot market prices. That of course assumes that the caps aren't hard caps, and that they allow the developers to benefit from those spot market prices during higher-priced periods. So ultimately, again, much of this comes down to the fundamental policy design. And finally, feed-in premiums are often argued to be better oriented to market demand. So if market demand is very low, many projects—that should lead to lower prices and therefore less supply.

Now, a few disadvantages, before wrapping up. Feed-in premiums arguably provide less investment certainty compared to feed-in tariffs, again, depending on the design. There typically is no purchase guarantee, so in contrast to a feed-in tariff, where you're effectively guaranteed an off-take price for a long-term period of time, under a feed-in premium, you don't have that guarantee. So you are essentially a free actor selling your power onto the wholesale market, and you need to make sure that someone's there to buy it on the other side of the trade. And in that sense you're exposed to higher off-take risk. In most cases, where markets are liquid, this isn't an issue, because the market demand is always there for that power to be purchased. But again, in periods of negative pricing, the dynamics here can shift. And under a premium FIT, developers would have to carry that risk, which also again means that it's more financially uncertain, which means that premium FITs as a general rule—again, depending on the design—would tend to result in higher investment costs, a higher weighted average cost of capital. As a result, this tends to lead to higher overall policy costs. Now, the big question here is whether those proportionally higher policy costs actually are offset by important policy gains, or policy cost savings—for example, from better project siting, from the avoidance of negative prices, from helping shave peak prices, by being more responsive. If premium policies were functioning properly and really providing dynamic price signals that were leading to more efficient operation of supply and demand, you could actually argue that any cost increase caused by premiums are offset by some of those policy gains, some of those policy-induced cost savings. But again, this becomes highly jurisdiction-specific, and often not only determined by factors within one jurisdiction itself, but often determined by network dynamics across the broader power system, across the balancing area, or even beyond into other balancing areas. So the dynamics there mean that it's very, very difficult to calculate precisely what the cost savings versus cost impacts would be, because again, what Germany does, for example, or what the Netherlands does, is not limited to these countries, their borders, and very substantial imports and exports on a monthly basis that can change the fundamental price dynamics and may, again in the long run, lead to any of a range of outcomes that can't be foreseen by policy makers when they establish, for example, a new feed-in premium policy. So the goal of a feed-in premium, in that sense, is to try to reduce the risks, provide the investment certainty within a certain degree, and still allow investments to take place while securing more market orientation from developers. One final challenge that is worth underscoring here is that under premium policies it's difficult for smaller projects, particularly say under one megawatt, or even under five megawatts, to sell their power directly on the wholesale market, for a host of reasons. Sometimes there are size thresholds for access to the wholesale market. Sometimes the transaction costs just don't make that make sense. And as a result, feed-in premiums may be less suitable for small-scale renewable energy projects versus large-scale renewable energy projects. So large-scale projects can often directly market onto the wholesale system. They can handle the transaction costs. They can orient themselves to the market. They can also invest more in forecasting technologies to provide more accurate forecasts. These are all things that small projects cannot easily or readily do without, again, fundamentally worsening the economics of the project. So there's a trade-off there, and that's one of the main reasons why some argue that feed-in premiums are less suitable for small-scale renewable energy projects. And in fact even the European Commission has accepted this line of reasoning in allowing fixed feed-in tariffs to continue for projects underneath a certain size. And depending on the jurisdiction, that threshold is 750 kilowatts, up to one or a few megawatts, depending on the technology. So there is a recognition of this reality.

Now, a few concluding remarks. Many countries continue to use both fixed FITs as well as feed-in premiums to govern renewable energy investment. So as we saw just a moment ago, it's possible to retain fixed FITs for projects say under one megawatt or under a few megawatts, and have a policy like a feed-in premium governing larger project sizes beyond that. In fact, this is arguably emerging as one of the main policy combinations, at least across Europe, to dealing with this particular challenge. And as more and more wholesale electricity markets are developed around the world, it's likely that policy makers are going to be encountering very much these same issues. And it can be expected with the European experience with feed-in premiums, contracts for differences, and so on, it's going to be very useful indeed in making better decisions about how to compensate renewable generators. A number of jurisdictions are moving toward premium FITs in order to improve market integration, but again this requires a functioning wholesale market, so feed-in premiums can't easily be introduced in markets without a wholesale- or some dynamic-price benchmark. And as we saw moments ago, many jurisdictions are also looking at contracts for differences, which can provide both a cap and a floor and thereby help reduce overall policy costs. So I think when you take a step back and you look at this unfolding evolution from feed-in tariffs to feed-in premiums, I hope you can now understand the background a little bit—why that evolution happened, what's been driving it. And also it remains the case that for jurisdictions that are starting to move away from feed-in tariffs and are wondering what else to do, auctions clearly remain one pathway where you essentially reintroduce long-term contracts. You just make sure that those contracts are competitively procured. But another approach is to move in the direction of these premium FITs and look at options like contracts for differences or the spot market gap model that can provide alternative solutions that encourage market integration of renewables and avoid the need for long-term fixed-price contracts, which auctions again typically also involve. There are hybrids now emerging, particularly in Europe, where what is actually being auctioned is no longer a fixed-price, long-term contract; it's a certain premium above some anticipated long-term wholesale market price—average market price. So essentially what the bidders are bidding for is how high the premium should be, what the premium FIT should be. And that remains yet another evolution in this discussion. And under those approaches they are using either a premium FIT like the one we saw, a wholesale spot market gap model, or some variation on contracts for differences to determine what that premium should be. So this essentially is the state of play. Again, much of this innovation has emerged in Europe, but this no doubt carries important and valuable lessons for jurisdictions well beyond Europe and around the world. So I've provided a little bit of further reading here, a couple key reports, including some that we've done, here for further analysis. And I'd like to take just a moment to thank again the International Solar Alliance for their support in preparing and funding this expert training series, and the Clean Energy Solutions Center for providing the platform and the logistics, and also just the network to make this possible. I'm Toby Couture with E3 Analytics, and it's been a pleasure having you here with me to talk about feed-in tariffs and feed-in premiums today. Now you'll shift to a quick knowledge checkpoint that involves a number of multiple-choice questions based on the presentation today. Thank you very much. I'm wishing you all a great day.